STATE OF NEW MEXICO

BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REGULATION
20.2.350 NMAC – *GREENHOUSE GAS CAP AND*
TRADE PROVISIONS **No. EIB 10-04 (R)**

REBUTTAL TESTIMONY OF CRAIG O'HARE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME.

A. My name is Craig D. O'Hare

Q. BY WHOM ARE YOU EMPLOYED, IN WHAT POSITION AND WHAT ARE YOUR AREAS OF RESPONSIBILITY?

A. I am the Special Assistant for Clean Energy in the Office of the Secretary in the New Mexico Energy, Minerals and Department. In this capacity, I am responsible for developing clean energy policies (energy efficiency, renewable energy, clean fuels, and efficient transportation) and legislation, and program development.

Q. PLEASE DESCRIBE YOUR EDUCATION AND WORK BACKGROUND.

A. I hold a Bachelor degree in Business Economics and Geography from the University of California - Santa Barbara. I have worked for environmental agencies in New Mexico and Arizona, and served as the Water Programs Administrator for the City of Santa Fe. My resume is attached as NMED-O'Hare Rebuttal Exhibit 1.

Q. FOR WHOM ARE YOU PRESENTING THIS REBUTTAL TESTIMONY?

A. I am testifying on behalf of the New Mexico Environment Department.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The New Mexico Environment Department has petitioned the Environmental Improvement Board to adopt a rule that regulates greenhouse gas emissions in New Mexico. On August 16, 2010, opponents of the petition filed their testimony. This testimony rebuts the testimony of electric utilities that are opposing NMED's petition.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The electric utilities claim that instituting a regionally-based cap on greenhouse gases (GHG) is unworkable due to statutory and/or Public Regulation Commission regulatory provisions. They suggest that the proposal will have a variety of negative consequences such as: (1) raise New Mexico consumers' energy expenditures; (2) result in GHG-emitting electric generating facilities being located out of state, thereby increasing GHG emissions (so-called "leakage"); (3) increase the use of inefficient generating units that are under the 25,000 tons per year threshold, and therefore increase both GHGs and costs to consumers; and (4) will not increase in-state investment of renewable energy resources. My rebuttal will demonstrate that these negative consequences are a worse case "the sky is falling" scenario that is very unlikely to actually occur. It is my expectation that a variety of other scenarios will emerge, demonstrating that the required GHG reductions are not only quite achievable, but may create significant positive societal outcomes, in addition to allowing New Mexico to do its "fair share" in reducing global GHG emissions. The main opportunity for controlling the costs of the proposed rule - energy efficiency - is substantially downplayed by the opponents. Thanks to statutory and regulatory changes in the past few years, it is primarily through energy efficiency that energy expenditures for citizens and businesses can remain manageable and the utilities can meet both the GHG reduction targets outlined in the proposed rule and continue to make a reasonable profit for their shareholders. In addition, the renewable energy requirements for investor-owned utilities in the Renewable Energy Act have been in place for five years now. As these requirements increase in stringency, they will substantially contribute to the utilities' ability to meet their GHG reduction targets under the proposed rule at no additional net cost to the utilities or their customers.

III. <u>REBUTTAL TO SPECIFIC CRITICISM OF THE PROPOSED RULE</u>

A. TESTIMONY OF CYNTHIA BOTHWELL (PNM)

NOTE: MANY OF MS. BOTHWELL'S OBJECTIONS TO THE PROPOSED RULE ARE REPEATED BY WITNESSES FOR THE OTHER UTILITES. TO AVOID REPETITION IN MY TESTIMONY, I WILL RESPOND ONCE TO EACH OBJECTION.

Q. MS. BOTHWELL TESTIFIES THAT NMED'S PROPOSED CAP AND TRADE PROGRAM IS INCONSISTENT WITH THE INTEGRATED RESOURCE PLANNING PROVISIONS IN THE EFFICIENT USE OF ENERGY ACT. DO YOU AGREE WITH THAT CONCLUSION?

A. No, I do not. By taking a holistic approach to generation and demand side resource decisions, "Integrated Resource Planning" (IRP) principles are wholly consistent with and specifically envision the possibility of a GHG regulatory regime. The Efficient Use of Energy Act states that "Utility integrated resource plans shall…take into consideration risk and uncertainty of fuel supply, price volatility and costs of anticipated environmental regulations in order to identify the most cost effective portfolio of resources…." (62-17-10 NMSA). The PRC, in turn, directed the utilities to include the potential future costs of carbon regulations as one of the "costs of anticipated environmental regulations" as required by the statute. Establishing a GHG regulatory regime tends to reduce, not increase, the uncertainty of the costs of emitting carbon. Once a GHG regulatory regime is well underway, the utilities' integrated resource plans will no longer need to speculate on the cost of carbon. Granted the later adoption of a federal cap-and-trade regime might alter the overall cost of carbon, and therefore, remains an uncertainty, a regional program will "set the stage" for utilities to deal with the reality of carbon emissions having a true cost rather than a "hypothetical" cost as in the existing IRPs.

Q. MS. BOTHWELL CLAIMS THAT THE PROPOSED CAP AND TRADE PROGRAM WILL NOT RESULT IN GREATER DEVELOPMENT IN RENEWABLE ENERGY AND ENERGY EFFICIENCY. DO YOU AGREE WITH THAT ASSESSMENT?

A. No, I do not. The renewable energy requirements in the state Renewable Energy Act (REA) and the energy efficiency requirements in the Efficient Use of Energy Act (EUEA) complement, rather than conflict, with the proposed cap and trade requirements. Both acts have, in essence, put the utilities on a path to comply with the cap and trade requirements, in advance of them being adopted. The cost of renewable energy has declined dramatically in the last decade, and the National Renewable Energy Laboratory projects further declines. If building and operating a renewable energy project is more cost-effective than other means for a utility to reduce its GHGs, which is entirely possible in the next decade, then more renewables will be brought on-line.

With respect to energy efficiency, Ms. Bothwell seems to suggest that since the EUEA requires them to bring energy efficiency resources on-line, that PNM will not do any more energy efficiency than is required. Mr. Bothwell must be concluding for some reason that the energy efficiency targets in the Act are actually caps to doing more energy efficiency, rather than as a minimum requirement. Since energy efficiency is the least cost resource, that does not make any sense. Furthermore, the EUEA requires that utilities "acquire all cost-effective and achievable energy efficiency and load management resources", (62-17-5.G, NMSA) suggesting that there is not a limit to utilities' pursuit of energy efficiency but, rather, energy efficiency must be maximized under the law. In a July 19, 2010 presentation to the New Mexico Science and Technology Legislative Interim Committee, PNM acknowledged that many energy efficiency measures can be acquired at $20 per megawatt hour, while new fossil fuel-derived electric generation cannot be acquired for less than $130 per megawatt hour. Energy efficiency is clearly a huge opportunity for utilities to reduce their GHG emissions in a cost-effective manner. Furthermore, as the proposed rule, in effect, results in a "CO2 cost adder" to the cost of fossil fuel generation, an even greater amount of energy efficiency measures will be deemed to be "cost-effective" and therefore pursued.

Q. MS. BOTHWELL INDICATES THAT BRINGING MORE RENEWABLE ENERGY INTO PNM'S SYSTEM THAN IS REQUIRED BY THE RENEWABLE ENERGY ACT VIOLATES THE "REASONABLE COST THRESHOLD" IN THAT STATUTE. IS THAT CORRECT?

A. No, it is not. In addition to including the consideration of the cost and operational impacts of bringing more renewable energy into a utility's system, the REA includes other factors to be considered when the Public Regulation Commission is establishing the Reasonable Cost Threshold (RCT). "In establishing and modifying the RCT, the commission shall take into account...the...life cycle cost on a net present value basis of renewable energy...and....other factors, including public benefits, that the commission deems relevant." (62-16-4.C NMSA). Ms. Bothwell's testimony is worded in such a way as to suggest that an absolute percent rate increase cap is "imposed by state law" (Bothwell, pg. 9, line 3) under the REA. There is no specific cap in the REA. The fact that the REA requires the cost of renewable energy to be evaluated on a "life cycle" basis recognizes that comparing the costs of renewable generation and traditional generation must be done on a "level playing field."

Q. WHAT DO YOU MEAN BY SUGGESTING THAT THE RENEWABLE ENERGY ACT ACKNOWLEDGES THAT THE COMPARISON OF RENEWABLE ENERGY COSTS AND NEW TRADITIONAL GENERATION COSTS MUST BE DONE ON A "LEVEL PLAYING FIELD" UNDER THE REASONABLE COST THRESHOLD?

A. Compared to traditional sources of power generation (e.g. natural gas and coal power plants), renewable energy projects are generally more expensive to build on a dollar per megawatt basis than traditional power plants. However, renewable energy projects have much lower operational costs than traditional power plants, primarily because the "fuel" (e.g., wind, sun, geothermal) is free. As fossil fuel energy costs rise over time, this contrast becomes even greater. Generally, the cost of new supply generation, expressed in dollars per megawatt-hour, is only derived for the period within which the capital costs are being paid off – usually 30 years. This is kind of like looking at the cost of homeownership only in the first 20 to 30 years the mortgage is being paid off. For those who have paid off their mortgage, the cost of homeownership drops dramatically down to primarily just utility bills, property taxes and repairs and upkeep. Renewable energy is similarly inexpensive once the capital costs are paid off compared to a fossil-fuel plant that still has to purchase the fuel. This is what is meant by "life cycle" cost comparison. Life cycle cost comparison puts all the costs on a level playing field.

Q. WHAT IS MEANT BY THE RENEWABLE ENERGY ACT REQUIREMENT THAT THE PRC MUST CONSIDER "PUBLIC BENEFITS" IN ESTABLISHING THE RCT?

A. That language is, of course, subject to interpretation by the PRC. But it is reasonable to suggest that "public benefits" means something more than and entirely separate from concerns about potential rate impacts to electric consumers, which is Bothwell's focus. I would suggest that economic development and job creation potential, positive public health impacts, and reducing GHG emissions which contribute to reducing the risk of global climate disruption, are all reasonable considerations under the notion of "public benefits".

Q. BUT HASN'T THE PRC ALREADY ESTABLISHED, BY RULE, THAT THE RCT IS TWO PERCENT IN 2011, RISING TO THREE PERCENT IN 2015?

A. Yes, that is true, but there is nothing in the existing rule that clarifies how that two to three percent is to be interpreted. The PRC is free to change its RCT rule at any point in time. In fact, the existing rule recognizes this possibility by saying that, "As changing circumstances warrant…the commission may modify the reasonable cost threshold." (17.9.572.11 NMAC). Clearly, the adoption of a GHG rule by the EIB falls easily within the notion of "changing circumstances" that the PRC could consider in amending the RCT.

Q. MS. BOTHWELL INDICATES THAT IF ENERGY EFFICIENCY SUBSTANTIALLY REDUCES PNM'S PEAK DEMANDS AND ENERGY LOADS, THE UTILITY WILL BE "PRECLUDE[D] FROM BUILDING NEWER, CLEANER RESOURCES BECAUSE THE UTILITY WILL NOT BE ABLE TO SHOW THE NEED FOR NEW FACILITIES AS IT IS REQUIRED TO DO IN A CCN PROCEEDING"? DO YOU AGREE WITH THIS CONCLUSION?

A. No, I do not. This is another one of those scare tactics that make no sense once some simple thought is given to it. If energy efficiency substantially reduces a utility's peak demands and annual energy requirements, then there may not be a <u>need</u> to build a new fossil fuel plant, or at least the construction of the plant can be delayed, or the size of the plant can be reduced. That's the ultimate benefit of having aggressive, effective energy efficiency programs. That's when the cost reduction benefits of energy efficiency can truly be realized: when they result in delaying or avoiding the capital costs of building a new plant. Whether it is a carbon-intensive coal plant or a less carbon intensive natural gas plant, efficiency encourages the utility to reduce its generation from the fossil fuel generation plants, and therefore, reduces GHG emissions. Even with effective energy efficiency programs, if a utility can still demonstrate that it needs additional supply generation resources, then it is difficult to believe that the PRC would not grant the necessary CCN (certificate of convenience and necessity) for the plant to be built.

Q. MS. BOTHWELL SUGGESTS THAT IN ORDER TO REDUCE GHG EMISSIONS, A UTILITY THAT REPLACES A BASE LOAD COAL PLANT THAT HAS LOWER FUEL COSTS WITH A NATURAL GAS PLANT THAT HAS MUCH HIGHER FUEL COSTS MUST REDUCE THE VALUE USED TO DETERMINE COST EFFECTIVE ENERGY EFFICIENCY MEASURES, AND THEREFORE REDUCES THE AMOUNT OF ENERGY EFFICIENCY THAT IS REQUIRED UNDER THE EUEA'S "ACQUIRE ALL COST-EFFECTIVE REQUIREMENT". DO YOU AGREE WITH THAT CONCLUSION?

A. No, I do not. In fact, it is just the opposite. When energy efficiency is compared to supply generation costs that are higher than they were previously, more energy efficiency measures satisfy the EUEA's "Total Resource Cost Test" (the criterion for determining whether an energy efficiency measure is "cost-effective"), and therefore more - not less - energy efficiency is acquired by the utility.

Q. THE UTILITIES ARGUE THAT THEY WILL SIMPLY BUILD NEW GENERATION RESOURCES OUT-OF-STATE IN ORDER TO CIRCUMVENT THE DEPARTMENT'S PROPOSED RULE AND THAT THIS WILL HAVE THE EFFECT OF INCREASING OVERALL GHG EMISSIONS. DO YOU AGREE WITH THIS CONCLUSION?

A. No I do not. This is the so-called "leakage" issue, which is a common argument by GHG emitters that do not want to be subject to GHG regulations. While it is conceivable that utilities could transfer their generation out-of-state, there are several factors that inhibit a utility's ability or even interest to do so. Locating generation resources out-of-state raises transmission access and new transmission permitting issues, as well as added cost concerns. Since energy efficiency is the least cost resource by more than $100 per megawatt-hour, it would be much more cost-effective for a utility to pursue substantive energy efficiency coupled with some in-state natural gas production to follow load than it would be to locate a new supply resource out-of-state.

Q. PNM ARGUES THAT, FROM AN OPERATIONAL PERSPECTIVE, THE CAP WILL HAVE THE EFFECT OF SHIFTING PRODUCTION FROM LOW GHG EMITTING GENERATION RESOURCES TO HIGHER GHG EMITTING GENERATION RESOURCES. BOTHWELL STATES THAT "IF THE UNITS SUBJECT TO THE CAP CANNOT BE USED, THE NEXT MOST ECONOMIC

UNIT WOULD BE USED – GENERALLY A LESS EFFICIENT UNIT – THAT MAY ACTUALLY HAVE HIGHER EMISSIONS." DO YOU AGREE WITH THIS CONCLUSION?

A. No, I do not. First of all, no one is saying that units subject to the cap "cannot be used". That makes it sound like, under the rule, the utilities will be forced to abandon all of their existing fossil fuel generation. Coal-fired power generation is the highest GHG emitter on a per megawatt-hour basis. More than likely, "the next most economic unit" would be a natural gas combined cycle unit – emitting much less than half the GHGs as the coal unit.

So to conclude, as Ms. Bothwell does, that the shift of production would be to a "generally [ ] less efficient unit" is not accurate. Note that just a few pages later (p. 26) , Ms. Bothwell appears to contradict herself by stating that, "In the near term, PNM will reduce GHG emissions largely by reducing output at its coal-fired units and replacing that output with higher output at its natural gas-fired units. GHG generation from gas generation can be as low as one-half the GHG emission level as coal."

Q. THE UTILITIES SUGGEST THAT THEY WILL NOT BE ABLE TO MAINTAIN SYSTEM RELIABILITY IF REQUIRED TO COMPLY WITH THE DEPARTMENT'S PROPOSED RULE. IS THAT AN ACCURATE CONCLUSION?

A. No, it is not. This is another scare tactic argument. The utilities want us to believe that if we adopt aggressive energy efficiency measures, bring more renewable energy on-line, and shift from coal to natural gas-fired generation, the citizens will be sitting in the dark and freezing due to power outages. There's nothing about energy efficiency and "demand response", in general, that jeopardizes NERC system reliability standards. In fact, many of the "smart grid" technologies that complement energy efficiency strategies may increase system reliability. As for overall system reliability, a recent report prepared on behalf of the Clean Energy Group' Clean Air Policy Initiative (a coalition of some of the nation's largest electric generators) states that, "electric system reliability will not be compromised if the industry and regulators proactively manage the transition to a cleaner, more efficient generation fleet." *Ensuring a Clean Modern Electric Generating Fleet while Maintaining System Reliability*, M.J. Bradley and Assoc., LLC, August 2010).

More specifically, a May 2010 study by the National Renewable Energy Laboratory, *Western Wind and Solar Integration Study,* concluded that "The technical analysis performed in this study shows that it is operationally feasible for the WestConnect region to accommodate 30% wind and 5% solar penetration" primarily using the existing infrastructure. NMED-O'Hare Rebuttal Exhibit 2. The study recognized that, in order to maintain system reliability under a 35% renewable energy scenario, that a change to transmission and distribution systems operations would need to occur. Furthermore, utilities often suggest that for every new renewable energy facility that is brought on-line, a new natural gas generation resource needs to be built to "back up" the intermittent nature of the renewable source – thus suggesting that renewable energy will increase system costs above just the cost of the renewable project. As part of the NREL study, however, it was noted that, "If key changes can be made to standard operating procedures, our research shows that large amounts of wind and solar can be incorporated onto the grid without a lot of backup generation." Substantive energy efficiency coupled with having 35% renewable energy on-line by 2020 would likely be much more than enough to meet the GHG reduction requirements in the rule.

Q. BUT WHAT ABOUT THE UTILITY SHIFTING FROM A LOW GHG EMITTING COMBINED CYCLE NATURAL GAS PLANT TO A HIGHER EMITTING COMBUSTION TURBINE NATURAL GAS (CT) PLANT THAT IS UNDER THE 25,000 MTON THRESHOLD? WON'T THAT RESULT IN A NET INCREASE IN EMISSIONS?

A. Yes, conceivably that could happen, but only to a very limited extent and only if the PRC allowed the utility to operate the much higher cost CT unit in that manner. For a 20 megawatt CT, the utility could only operate the plant for about 3 months before it exceeded the 25,000 mton threshold for coming under the regulatory regime. Given the limited number of CTs the utilities currently have, this approach to doing an "end around" the regulated cap would only serve a very small amount of their electric demand. And, of course, it is unlikely that the PRC would approve a utility's request for new CTs for the obvious purpose of avoiding the GHG regulation.

Q. MS. BOTHWELL TESTIFIES THAT THE GHG REDUCTION STRATEGIES IDENTIFIED BY NMED WITNESS DR. SAHU WILL NOT HELP WITH REDUCING GHG EMISSIONS. DO YOU AGREE?

A. No, I do not. Ms. Bothwell's generic response to most of Dr. Sahu's suggested strategies is essentially "we're already doing it", suggesting that there cannot possibly be any additional GHG reductions available from the measures. From demand side management (i.e. energy efficiency and conservation), to reducing line losses, improving fuel efficiency, and increasing renewable resources, PNM and the other utilities have hardly maximized the potential in these areas. Particularly for energy efficiency - one of the most promising and cost-effective areas for GHG reduction - PNM and the other investor-owned utilities only initiated substantive programs a few years ago. There are still a myriad of cost-effective "low hanging fruit" measures waiting to be implemented.

Q. DO THE INVESTOR-OWNED UTILITIES RECOGNIZE THE NEED TO PLAN FOR CLIMATE CHANGE?

A. Yes. Despite the lack of absolute certainty around climate change, all three of the state's investor-owned utilities recognize the need to address climate disruption by regulating GHGs. PNM has publicly stated that it favors a federal policy to deal with climate change, and Xcel/Southwestern Public Service Company's witness, Jack Ihle, states that the company favors a federal policy. (page 3, line 22). El Paso Electric's witness, William P. Patton, states that "El Paso Electric would support a sound, broad-scale approach to greenhouse gas regulation at such time as there is a national consensus to do so." (page 12, lines 28-29).

B. TESTIMONY OF JACK IHLE (SOUTHWESTERN PUBLIC SERVICE)

Q. MR. IHLE INDICATES THAT THE PROPOSED RULE WOULD INCREASE ELECTRICITY RATES BY 4 TO 20% RANGE BY 2020. DO YOU AGREE?

A. I believe that the proposed rule is likely to increase electric rates, but I am not in a position to agree or disagree with Mr. Ihle's estimate of the increase. While it is not for me to say whether an increase between 4 and 20% over 8 years is either reasonable or not, it is important to note that this range is comparatively low in contrast to the rate increases recently obtained and currently proposed by some of New Mexico's utilities, rate increases which, in large part, are not about the costs of reducing GHG emissions.

But the most important point is to emphasize that citizens and businesses don't pay "rates"; they pay "bills". The electric rate, alone, does not determine a citizen's or business' monthly electricity expenditures. Monthly usage or "demand" is, of course, the other variable that determines the ultimate amount of the bill. As I stated earlier, there is enormous opportunity for cost-effective energy efficiency (technology measures) and energy conservation (behavioral changes to energy use) to reduce the energy usage of homeowners, businesses, and industry. For example, if the proposed rule increases electric rates by 5% by 2020 but customers reduce their electricity consumption by 10-20% (an entirely achievable reduction for many consumers), their monthly electric bills will actually decrease. Energy efficiency is not about sacrificing comfort as some would suggest. Energy efficiency is about getting the same level of energy services (heating, cooling, refrigerating food, lighting, etc.) delivered using less energy. As one energy efficiency expert put it, we can still have cold beers and hot showers while using a lot less energy.

Q. MR. IHLE SUGGESTS THAT THE PROPOSED RULE WILL "HINDER JOB CREATION". DO YOU AGREE WITH THAT CONCLUSION?

A. No, I do not. Mr. Ihle does not provide any documentation or analysis to support such a claim. I would argue that it is quite possible that the proposed rule will actually stimulate job creation, particularly in the areas of roof-top solar installations and energy efficiency renovations of existing buildings. Both measures will not only contribute to GHG emission reductions, but also will help stimulate a building industry that has experienced a significant slow down since the economic downturn.

C. TESTIMONY OF ROBERT KAPPELMAN (CITY OF FARMINGTON)

Q. HOW DO YOU RESPOND TO MR KAPPELMANN'S CONCLUSION ABOUT THE COST IMPACT OF THE DEPARTMENT'S PROPOSED RULE ON THE FARMINGTON ELECTRIC UTILITY SYSTEM?

A. Starting on page 15 of his testimony, Mr. Kappelmann describes his analysis and results. He calculates costs to the system assuming high and low allowance prices estimates for the Waxman-Markey House bill and the addition of "zero" emission energy sources during the study period. He does not assume the use of energy efficiency strategies to reduce emissions. Mr. Kappelmann believes system costs associated with the NMED rule will closely track the low allowance cost scenario in the early years and the high allowance cost scenario in subsequent years out to 2050. Mr. Kappelmann cites Graph 1 on the third page of his first exhibit to illustrate the predicted costs to the system. Under the low allowance price scenario (Case A Cost) the cost impact curve is almost flat out to 2020, indicating that we should expect, at most, a modest cost increase from 2012 through 2020. The Department is proposing to sunset emission reductions in 2020, and therefore cost estimates beyond this point are irrelevant to this hearing. The fact that Mr. Kappelman's assumptions did not include cost-effective energy efficiency measures suggests that his cost estimates could be even lower.

D. OTHER CONSIDERATIONS

Q. IS THERE ANYTHING THAT YOU WOULD LIKE TO ADD TO YOUR TESTIMONY?

A. Yes. Three of the four electric utilities opposing the proposed rule are private companies that are "regulated monopolies" overseen (or "regulated") by the Public Regulation Commission. Regulated private company monopolies have the exclusive right to provide a service and make a profit in an identified area, free from the competition from other potentially competing companies. Generally, regulated monopolies are established by government for the delivery of certain "public" services (water, telephone, electricity, etc.) where the service is more cost-effectively provided by one entity rather than a whole host of competing companies – because it would not make any sense to duplicate the infrastructure necessary to provide the service. Imagine you could buy water from ten different private water companies and that there were ten different water lines coming to your home! Because of the "public service" nature of monopolies, many are actually operated by governments such as municipalities. In fact there are over 250 government-owned and run electric and natural gas utilities in the country.

My basic point is that climate disruption is a critical public policy issue facing New Mexicans over the long term. Since regulated private sector monopolies provide a public service and enjoy the privilege of being free from outside competition, it is, in my opinion, reasonable to expect them to not oppose helping to address and resolve important public policy issues such as climate disruption. The New Mexico Public Utility Act recognizes that the Public Regulation Commission's responsibility in regulating utilities is not just about keeping rates as low as possible and ensuring that the stockholder makes a fair rate of return on his/her investment, but that promoting the public interest also is an important consideration that must be weighed and balanced with the other two considerations: "In order to represent the public interest, the utility division shall present to the commission its beliefs on how the commission should fulfill its responsibility to balance the public interest, consumer interest, and investor interest." (8-8-12.C NMSA).

I am not saying that the utilities should not be concerned about rate impacts to their customers or profits to their stockholders, but that by providing what many consider to be a quasi-governmental service, they have an obligation to be concerned about the common good and the general welfare of citizens. Although all three investor-owned utilities appear to support climate change action at the federal level, I continue to believe that their opposition to a western regional cap-and-trade program is not in the public interest of New Mexico.

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WORK EXPERIENCE

NEW MEXICO ENERGY, MINERALS AND NATURAL RESOURCES DEPT. (2003-present)
Special Assistant for Clean Energy, Gubernatorial Appointee

Provide policy and program implementation direction to achieve Governor Richardson's clean energy objectives in the areas of renewable energy, green building, energy efficiency, and efficient transportation and clean fuels. Department's lead lobbyist at the NM State Legislature for the Governor's clean energy legislative initiatives: legislation preparation and analyses, assisting bill sponsors (Senators and Representatives), presentations to interim committees, assisting other state departments (Economic Development, Environment) with clean energy-related legislation, testifying in committees, serving as an expert witness on the House and Senate floors, etc. Successfully adopted legislation include: NM Renewable Energy Transmission Authority Act, Motor Vehicle Excise Tax Exemption for Hybrid Vehicles, Renewable Portfolio Standard, Efficient Use of Energy Act, Clean Energy Revenue Bond Act, Advanced Energy Tax Credit Act, Alternative Energy Product Manufacturers Tax Credit Act, Renewable Energy Production Tax Credit. Generate draft gubernatorial Executive Orders and administer various clean energy stakeholder task forces established by the Governor. Interface with the NM Renewable Energy Transmission Authority and lead staff person to the Governor's Electric Transmission Planning Task Force. Work closely with state and local economic development agencies and renewable energy developers to attract the clean energy industry to New Mexico. Represent the Administration by participating on and making presentations to various stakeholder associations, workshops, task forces, conferences, etc., both in and out-of-state (e.g. Western Governors' Association). Serve as the Department's lead staff person for the Governor's Climate Change Initiative and at Public Regulation Commission proceedings. Position answers directly to Cabinet Secretary Jim Noel.

CITY OF SANTA FE, WATER DIVISION (1996-2002)
Water Programs Administrator

Administer demand management (conservation and water use efficiency) and drought emergency programs. Research and draft water management-related ordinances. Manage the 1996, 2000, and 2002 water shortage emergency demand reduction programs. Supervise water conservation and field compliance staff. Perform public relations functions: prepare public information/outreach materials, media relations, radio interviews, and public presentations to community organizations. Draft a domestic well ordinance restricting new wells in the City's service area and administer the ordinance. Coordinate with Santa Fe National Forest on municipal watershed restoration plan to reduce extreme fire danger and enhance water yield. Administer watershed forest thinning contract on City lands. Serve as the Division's lead for Y2K preparation and public information activities. Lobby at the New Mexico State Legislature and U.S. Congressional Delegation on the City's water-related funding and legislative objectives. Participate on the Governor's Drought Task Force Drinking Water Subgroup. Prepare N.M. Finance Authority and N. M. Water Trust Board grant applications for capital projects.

NEW MEXICO CONSERVATION VOTERS ALLIANCE (1996, 1995)
Lobbyist, New Mexico State Legislature, 1995 and 1996 Legislative Sessions

Analyze legislation and draft amendments. Meet with State of New Mexico legislators on proposed legislation. Testify at committee hearings. Coordinate issues and strategies with other organizations and state agencies. Supervise volunteers. Draft issue papers, action alerts, and articles for distribution.

NMED - O'HARE
REBUTTAL EXHIBIT 1

NEW MEXICO ENVIRONMENT DEPARTMENT (1995)
Environmental Specialist, Solid Waste Bureau

Establish and administer a Source Reduction and Recycling Stakeholder Working Group pursuant to House Memorial 31 (1995 New Mexico Legislature): research source reduction strategies, review relevant state statutes, prepare issue papers, chair the committee. Assist with drafting the 1995 Annual Solid Waste Report to the Legislature. Research pollution prevention strategies and prioritize for possible implementation by New Mexico regulatory agencies. Draft a Communication Plan to publicize program to industry sector.

CITY OF TUCSON, ARIZONA, Ward VI City Council Office (1990-1994)
Council Executive Assistant, City Councilmember Molly McKasson,

Research, draft, and review legislation, prepare position papers and correspondence. Review Mayor and Council agenda materials, and evaluate for consistency with Councilmember's policy objectives. Represent the Councilmember at public meetings and forums. Environmental Programs Focus: comprehensive solid waste/waste reduction plan, recycled materials procurement policy, conservation-targeted water rate structures, groundwater contamination and remediation oversight, transportation planning and alternate transportation modes utilization, and energy conservation policies/ordinances. Additional priorities: tracking state and federal legislation and diversifying economic development efforts (including economic conversion planning for defense-dependent industries). Review, make recommendations, and track expenditures of City's $500 million per year capital and operating budget. Investigate and propose areas for budget efficiencies while preserving public services. Volunteer for Councilmember's successful election and reelection campaigns: policy positions and election strategy development, phone banking, door-to-door contact, coordinating volunteers, GOTV, etc.

ARIZONA DEPARTMENT OF WATER RESOURCES, Tucson (1984-1989)
Water Resource Specialist

Review and draft water-related state legislation to promote agency objectives. Program Coordinator for the turf industry mandatory water conservation program: researching and drafting conservation requirements, chairing a technical advisory committee. Critique and draft elements of a comprehensive groundwater management plan to implement 1980 Arizona Groundwater Code water management requirements. Chair an interagency rule-making committee to implement the 1986 Groundwater Recharge Act "safe-yield" requirements. Review and process groundwater recharge permit applications. Project Manager for the development of a tri-agency sponsored groundwater recharge facility. Research and draft a water quality protection plan. Serve as regulatory enforcement staff to ensure compliance with water conservation regulations.

<u>EDUCATION</u>

UNIVERSITY OF CALIFORNIA, SANTA BARBARA (1977-1981)
B.A. Business Economics and B.A. Geography (Overall Grade Point Average: 3.6)

UNIVERSITY OF ARIZONA, Tucson (1983-1984)
Graduate Studies in Water Resources Administration

<u>REFERENCES</u> Available Upon Request

August 2010

904 Task Force

904 Categories
site evaluator
system designer
installer 1 and 2
wastewater reuse irrigator
inspector
maintenance service provider
septage pumper

Issue: Are these the appropriate categories?
Task Force is working with
Installer 1 and 2
Site Evaluator
System Designer
Inspector
NMED Staff
MSP

904 NMED Inspectors
904 requires that employees shall be certified afer completing a program and passing an exam approved by the Department.

Issue: Can we do this under existing union agreements? What would need to be done? What are acceptable alternatives?

904 Certification Requirements
904 sets forth basic KSAs for each category. Installers and wastewater reuse irrigation service providers are required to have a contractors license.

The Task Force is developing KSAs

Courses:

Has any process been worked on? Maybe they are waiting on the KSAs.




WESTERN WIND AND SOLAR INTEGRATION STUDY

PREPARED FOR:
THE NATIONAL RENEWABLE ENERGY LABORATORY

PREPARED BY:
GE ENERGY

MAY 2010

WESTERN WIND AND SOLAR INTEGRATION STUDY

May 2010
Prepared for NREL by GE Energy
1 River Road
Schenectady, New York 12345
Technical Monitor: Debra Lew
Prepared under Subcontract No. AAM-8-77557-01

Subcontract Report
NREL/SR-550-47434

National Renewable Energy Laboratory
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303-275-3000 • www.nrel.gov
NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC
Contract No. DE-AC36-08GO28308

Cover photos (from left to right): PIX # 15996, 08604, 10927 and 14898

ACKNOWLEDGMENTS

The National Renewable Energy Laboratory (NREL) thanks the U.S. Department of Energy (DOE) for sponsoring the Western Wind and Solar Integration Study. Contributors include:

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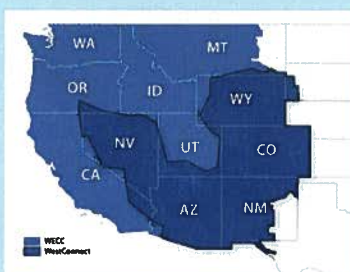
Finally, we thank Bruce Green (NREL) and Mark Schroder (Purple Sage Design) for designing this Executive Summary and the full report.

INTRODUCTION

The focus of the Western Wind and Solar Integration Study (WWSIS) is to investigate the operational impact of up to 35% energy penetration of wind, photovoltaics (PVs), and concentrating solar power (CSP) on the power system operated by the WestConnect group of utilities in Arizona, Colorado, Nevada, New Mexico, and Wyoming[1]. WWSIS was conducted over two and a half years by a team of researchers in wind power, solar power, and utility operations, with oversight from technical experts in these fields. This report discusses the development of data inputs, the design of scenarios to address key issues, and the analysis and sensitivity studies that were conducted to answer questions about the integration of wind and solar power on the grid.

WESTCONNECT

WestConnect is a group of transmission providers that are working collaboratively on initiatives to improve wholesale electricity markets in the West. Participants include Arizona Public Service, El Paso Electric Co., NV Energy, Public Service of New Mexico, Salt River Project, Tri-State Generation and Transmission Cooperative, Tucson Electric Power, Western Area Power Administration, and Xcel Energy.



The technical analysis performed in this study shows that it is operationally feasible for WestConnect to accommodate 30% wind and 5% solar energy penetration, assuming the following changes to current practice could be made over time:

- Substantially increase balancing area cooperation or consolidation, real or virtual;
- Increase the use of sub-hourly scheduling for generation and interchanges;
- Increase utilization of transmission;
- Enable coordinated commitment and economic dispatch of generation over wider regions;
- Incorporate state-of-the-art wind and solar forecasts in unit commitment and grid operations;
- Increase the flexibility of dispatchable generation where appropriate (e.g., reduce minimum generation levels, increase ramp rates, reduce start/stop costs or minimum down time);
- Commit additional operating reserves as appropriate;
- Build transmission as appropriate to accommodate renewable energy expansion;
- Target new or existing demand response programs (load participation) to accommodate increased variability and uncertainty;
- Require wind plants to provide down reserves.

In addition, suggestions for follow-on work to further explore these and additional mitigation options are listed in the Conclusions and Next Steps section.

[1] WestConnect also includes utilities in California, but these were not included in WWSIS because California had already completed a renewable energy integration study for the state.

BACKGROUND

WWSIS and its sister study, the Eastern Wind Integration and Transmission Study (EWITS), follow the U.S. Department of Energy's (DOE) 20% Wind Energy by 2030 Study that considered the benefits, costs, and challenges associated with sourcing 20% of the nation's energy from wind power by 2030 [1, 2]. The study found that while proactive measures were required, no insurmountable barriers to reaching 20% wind were identified. Thus, DOE and the National Renewable Energy Laboratory (NREL) embarked upon WWSIS and EWITS to examine, in much greater depth, whether there were technical or physical barriers in operating the grid with 20% wind. Solar power was included in WWSIS due to the significant solar resources and solar development in the West.

BALANCING AREAS

Balancing areas are responsible for balancing load and generation within a defined area and maintaining scheduled interchanges with other balancing areas.

Four of the five states in WestConnect have Renewables Portfolio Standards (RPS) that require 15-30% of annual electricity sales to come from renewable sources by 2020-2025. Additionally, WWSIS models the entire western interconnection, examining the operating impact of up to 23% penetration of wind and solar in the rest of the Western Electricity Coordinating Council (WECC). Most of the states in WECC have similar RPS requirements and renewable energy growth in the region has been significant.

The study was designed to answer questions that utilities, Public Utility Commissions, developers, and regional planning organizations had about renewable energy use in the West:

- What is the operating impact of up to 35% renewable energy penetration and how can this be accommodated?
- How does geographic diversity help to mitigate variability?
- How do local resources compare to remote, higher quality resources delivered by long distance transmission?
- Can balancing area cooperation mitigate variability?
- How should reserve requirements be modified to account for the variability in wind and solar?
- What is the benefit of integrating wind and solar forecasting into grid operations?
- How can hydro generation help with integration of renewables?

WWSIS and its sister study EWITS build upon a large body of work on wind integration [3-9]. Previous studies examined specific utilities or states, looking at the impact of wind on operations in the regulation (seconds to minutes), load following (minutes to hours), and unit commitment (hours to days) time frames. In these studies, hypothetical wind and transmission build-outs were typically added to the existing system, which was simulated or statistically analyzed over these time frames. These studies generally consider the impact of the variability of wind (due to varying weather) and the uncertainty of wind (due to our inability to perfectly forecast the weather). Even if the weather and the wind could be perfectly forecast,

STUDY ASSUMPTIONS

SCENARIO DEVELOPMENT:

- Specific energy targets for each of three technologies: wind, PV, and CSP were fixed. For example, wind sites could not be traded out for CSP sites.
- A number of capital cost assumptions in 2008 dollars were used in determining the different geographic scenarios: wind at $2000/kW, PV at $4000/kW, CSP with thermal storage at $4000/kW, transmission at $1600/MW-mile, and transmission losses at 1% per 100 miles. No tax credits are assumed or included.
- The geographic scenarios considered different interstate transmission build-outs and included these costs in the scenarios. Incremental intra-state transmission build-outs were not specified in this analysis. Existing transmission capacity is assumed to be unavailable for new renewable energy generation only for the scenario development process.
- New transmission was undersized: 0.7 MW of new transmission was added for each 1.0 MW of remote generation.

PRODUCTION SIMULATION ANALYSIS:

- All study results are in 2017 nominal dollars with 2% escalation per year.
- $2/MBTU coal; $9.50/MBTU natural gas.
- Carbon dioxide costs were assumed to be $30/metric ton of CO_2.
- Except in cases where specified, extensive balancing area cooperation is assumed (see box on page 19).
- The production simulation analysis assumes that all units are economically committed and dispatched while respecting existing and new transmission limits and generator cycling capabilities and minimum turndowns.
- Existing available transmission capacity is accessible to renewable generation.
- Generation equivalent to 6% of load is held as contingency reserves – half is spinning and half is non-spinning.
- The balance of generation was not optimized for renewables. Rather, a business-as-usual capacity expansion met projected load growth in 2017. Renewable energy capacity was added to this mix, so the system analyzed is overbuilt by the amount of capacity value of the renewable plants.
- Increased O&M of conventional generators due to increased ramping and cycling was not included due to lack of data.
- Renewable energy plant O&M costs are not included. Wind and solar are considered price-takers.
- The hydro modeling did not reflect the specific climatic patterns of 2004, 2005, and 2006, but rather a 10-year long term average flow per month.
- The sub-hourly modeling assumes a 5-minute economic dispatch.

grid operators would still have to accommodate wind's variability. It is important to note that operators already manage variability and uncertainty in the load; wind and solar add to that variability and uncertainty.

WWSIS was funded by DOE and was managed by NREL. The main partner in this study was WestConnect. The project team included 3TIER Group (wind power dataset, and wind and solar forecasts), State University of New York at Albany/Clean Power Research (solar radiation dataset), Exeter Associates (data collection), Northern Arizona University (wind validation and hydro), NREL (wind validation, and PV and CSP power datasets), and GE (scenarios, and main technical/economic analysis). A Technical Review Committee (TRC), composed of members of WestConnect utilities, western utility organizations, and industry and technical experts, met eight times to review technical results and progress. A broader stakeholder group, open to the public, met five times to ensure study direction and results were relevant to western grid issues. Interim and final results of this study have been vetted in approximately 30 public forums.

The study examined grid operation for the year 2017. That is, system loads and generation expansion were projected to represent year 2017. While 35% renewable energy penetration was not expected by 2017, this year was selected in order to start with a realistic model of the transmission grid. The study examined inter-annual operability by modeling operations for year 2017 three times, using historical load and weather patterns from years 2004, 2005, and 2006.

WHAT THIS STUDY DOES AND DOES NOT COVER

While this study undertakes detailed analysis and modeling of the power system, it was meant to be a complement to other in-depth studies:

- WWSIS is an operations study, not a transmission planning study, although different scenarios model different interstate transmission expansion options.
- WWSIS is not a cost-benefit analysis, even though wind and solar capital costs were incorporated in scenario development. Rather WWSIS focuses on the variable operational costs and savings due to fuel and emissions.
- WWSIS is not a reliability study, although analysis of the capacity value of wind and solar was conducted to assess their contributions to resource adequacy. A full complement of planning and operational electrical studies would be required to more accurately understand and identify system impacts.
- WWSIS does not address dynamic stability issues.
- WWSIS does not attempt to optimize the balance between wind and solar resources. Wind and solar levels were fixed independently.

In 2017, it is anticipated that WestConnect and WECC will operate differently from current practice. WWSIS assumed the following changes from current operational practice:

- Production simulations of WECC grid operations assume least-cost economic dispatch in which all generation resources are shared equally and not committed to specific loads. Except for California and Alberta, WECC currently utilizes a bilateral contract market with long and short-term contracts in which resources are contracted out to meet specific loads.
- Other than California and Alberta, WECC currently operates as 37 separate balancing areas that utilize these bilateral contracts to balance their areas. Except where specified, this study assumes five regional balancing areas in WECC (Arizona-New Mexico, Rocky Mountain, Pacific Northwest, Canada and California). WWSIS does not consider any power purchase agreements, including those for renewables[2].
- Except for California and Alberta, transmission in WECC is primarily contractually obligated and utilized. Existing available transmission capacity may be contractually obligated and not accessible to other generation. This study assumes that existing available transmission capacity is accessible to other generation on a short-term, non-firm basis.
- Pricing developed by production cost modeling can vary widely from bilateral contract prices, and was not aligned or calibrated with current bilateral contract prices. The incremental operations and maintenance (O&M) costs in the report do not necessarily replicate escalated current costs in the Western Interconnection.

In addition to these caveats, there are reasons that the study results tend toward the conservative:

- WWSIS did not model a more flexible non-renewable balance of generation than what exists and is planned in WECC today. If 20-35% variable generation were to be planned in WECC, more flexible generation would be likely planned as well, reducing the challenge that wind and solar place on operation in this study.
- This study modeled the grid for the year 2017. If WWSIS were conducted for a later year when 35% renewables would be more plausible, the power system would likely have a larger load, more flexible balance of generation, and more transmission, all of which would help to accommodate the renewables.
- The wind dataset used was conservative in terms of overestimating the actual variability found in measured wind plant output.
- The base assumption of $9.50/MBTU for gas means that gas is displaced, which leaves coal (which in the West, is less flexible than gas) to accommodate the variability of the renewables.

[2] *Thus, throughout this work, costs specifically and solely refer only to variable costs, i.e., fuel plus O&M plus carbon tax, that are incurred during operation. Prices paid to individual generators are not reported.*

SCENARIOS

WIND, SOLAR, AND LOAD DATA

About 75 GW of wind generation sites were required for the study scenarios. Because there are not adequate measurements of wind speed or wind power to model this amount of wind generation, 3TIER Group employed a mesoscale Numerical Weather Prediction (NWP) Model to essentially recreate the weather in a 3-dimensional physical representation of the atmosphere in the western U.S. for the years 2004-2006. They then sampled this model at a 2-km, 10-minute resolution and modeled wind plants throughout this region, based on a Vestas V90 3-MW turbine. 3TIER Group also developed day-ahead wind forecasts for each hour. Over 960 GW of wind sites were modeled. The wind dataset is publicly available [10, 11].

Similarly, a lack of solar irradiance or power measurements led to the use of a satellite cloud cover model to simulate the United States at a 10-km, hourly resolution [12]. Day-ahead hourly solar forecasts were also developed [10]. PV was modeled in 100-MW blocks as distributed generation on rooftops because modeling information for large, central station PV plants was not available at the time of the study. Over 15 GW of PV plants were included in the dataset. Ten-minute variability was subsequently added to the aggregate hourly outputs to create the 10-minute PV data.

CSP was modeled as 100-MW blocks of parabolic trough plants with six hours of thermal storage. Over 200 GW of CSP plants were modeled in the dataset. Because the CSP with thermal storage produces a very stable output, the 10-minute dataset was created simply by interpolating the hourly dataset.

Hourly load-profile data for all operating areas in WECC were obtained from a Ventyx database, and 10-minute load data were derived by interpolating the hourly data.

SCENARIO DESCRIPTION

The WWSIS used a multidimensional scenario-based study approach to evaluate:

- Different levels of energy penetration for wind and solar generation, ranging from 11% to 35%;
- Different geographic locations for the wind and solar resources;
- A wide array of sensitivities to assess issues such as fuel costs, operating reserve levels, unit commitment strategies, storage alternatives, balancing area size, etc.

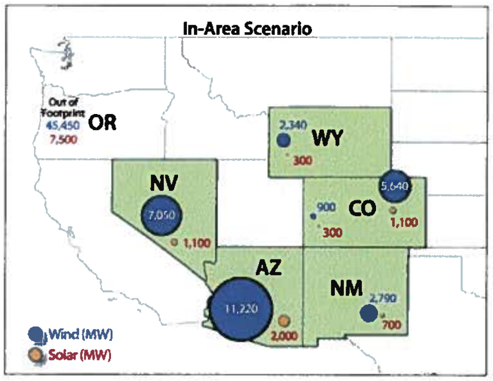
Table 1 shows the four levels of wind and solar energy penetration assumed for the study scenarios. The **Preselected case** includes that wind and solar capacity which was installed by the end of 2008. The **10% case** includes 10% wind energy (relative to total annual load energy) and 1% solar energy (solar consisted of 70% CSP and 30% PV) in the study footprint, as well as the rest of WECC. The **20% case** includes 20% wind energy and 3% solar energy in the study footprint, with 10% wind energy and 1% solar energy in the rest of WECC. The **20/20% case** includes 20% wind energy and 3% solar energy in the study footprint, as well as the rest of WECC. The **30% case** included 30% wind energy and 5% solar energy in the study footprint, with 20% wind energy and 3% solar energy in the rest of WECC.

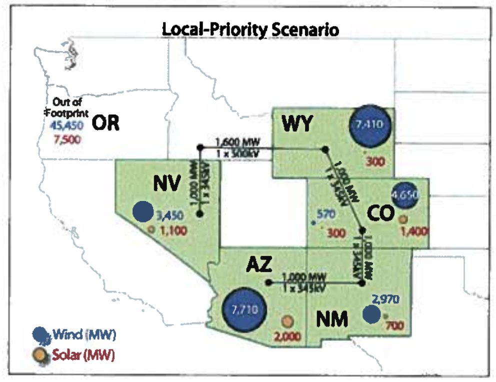
TABLE 1 – WIND AND SOLAR ENERGY PENETRATIONS FOR WWSIS CASES WITH NAMING CONVENTION IN BLUE.

CASE NAME	IN FOOTPRINT			REST OF WECC	
NAME	WIND + SOLAR	WIND	SOLAR	WIND	SOLAR
PRE-SELECTED CASE	3%*	3%	*	2%	*
10% CASE	11%	10%	1%	10%	1%
20% CASE	23%	20%	3%	10%	1%
20/20% CASE	23%	20%	3%	20%	3%
30% CASE	35%	30%	5%	20%	3%

Existing solar embedded in load

Three geographic scenarios were developed to examine the tradeoff between: 1) local resources that are closer to load, but have lower capacity factors and 2) remote resources that have higher capacity factors, but require long distance transmission to access loads. An algorithm was developed to select sites based on energy value, capacity value, and geographic diversity according to criteria developed for each scenario. Figure 1 shows maps of the study scenarios for the 30% case. Total nameplate ratings of wind generation for each state are shown in blue; solar MW ratings are shown in red. New transmission lines to increase interstate transfer capability are shown in black. Significant intra-state transmission also needs to be built to bring the renewable resources to the existing bulk transmission grid, but WWSIS did not examine intra-state transmission.





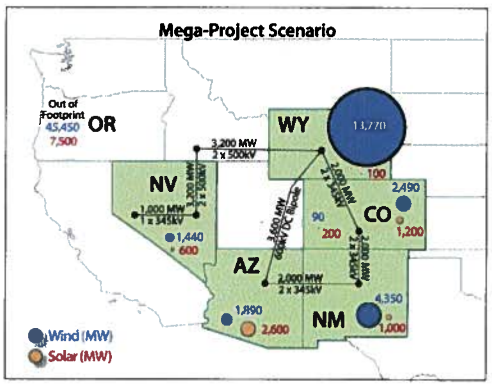


Figure 1 – Three geographic scenarios developed for siting of wind and solar plants in the 30% case, with appropriate interstate transmission included to bring resources to load.

In Area Scenario: Each state in the study footprint met its wind and solar energy targets using the best available wind and solar generation resources within its state boundary. No additional interstate transmission was added.

Local Priority Scenario: This scenario used the best wind and solar sites within the entire footprint, but included a 10% capital cost advantage to resources within each state. The result was a scenario that was about halfway between the In Area and Mega Project Scenarios. This scenario includes new interstate transmission, but not as much as the Mega Project Scenario.

Mega Project Scenario: The study footprint met its wind and solar energy targets by using the best available wind and solar resources within the study footprint. Given that many of the best wind resources are in Wyoming, this scenario includes a large penetration of wind generation in Wyoming (and other wind-rich areas), with new transmission lines to deliver the energy to load centers.

For all three of these scenarios, the rest-of-WECC scenario remains constant: each state in the rest of WECC meets its renewable energy target using the best available resources within the state boundary.

Table 2 shows a summary of the total wind and solar MW ratings by state for the three study scenarios. Table 3 summarizes the capital costs for the three study scenarios.

TABLE 2 – SUMMARY OF AGGREGATED WIND AND SOLAR MW RATINGS BY STATE FOR WWSIS SCENARIOS

IN AREA

			10%	1%	20%	3%	30%	5%
AREA	LOAD MIN. (MW)	LOAD MAX. (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)
ARIZONA	6,995	23,051	3,600	400	7,350	1,200	11,220	2,000
COLORADO EAST	4,493	11,589	2,040	300	3,780	800	5,640	1,400
COLORADO WEST	712	1,526	300	0	600	200	900	300
NEW MEXICO	2,571	5,320	1,080	200	1,920	400	2,790	700
NEVADA	3,863	12,584	2,340	200	4,680	700	7,050	1,100
WYOMING	2,369	4,016	930	100	1,620	100	2,340	300
IN FOOTPRINT	**21,249**	**58,087**	**10,290**	**1,200**	**19,950**	**3,400**	**29,940**	**5,800**

LOCAL PRIORITY

			10%	1%	20%	3%	30%	5%
AREA	LOAD MIN. (MW)	LOAD MAX. (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)
ARIZONA	6,995	23,051	2,850	400	5,2550	1,200	7,710	2,000
COLORADO EAST	4,493	11,589	2,190	300	3,870	800	4,650	1,400
COLORADO WEST	712	1,526	210	0	450	200	570	300
NEW MEXICO	2,571	5,320	1,350	200	2,100	400	2,970	700
NEVADA	3,863	12,584	1,350	200	2,490	700	3,450	1,100
WYOMING	2,369	4,016	1,650	100	4,020	100	7,410	300
IN FOOTPRINT	**21,249**	**58,087**	**9,600**	**1,200**	**18,180**	**3,400**	**26,760**	**5,800**

MEGA PROJECT

			10%	1%	20%	3%	30%	5%
AREA	LOAD MIN. (MW)	LOAD MAX. (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)	WIND (MW)	SOLAR (MW)
ARIZONA	6,995	23,051	810	400	1,260	1,200	1,890	2,600
COLORADO EAST	4,493	11,589	2,010	300	2,400	800	2,490	1,200
COLORADO WEST	712	1,526	60	0	90	200	90	200
NEW MEXICO	2,571	5,320	1,860	200	2,700	400	4,350	1,000
NEVADA	3,863	12,584	570	200	1,020	700	1,440	600
WYOMING	2,369	4,016	3,390	100	8,790	100	13,770	100
IN FOOTPRINT	**21,249**	**58,087**	**8,700**	**1,200**	**16,260**	**3,400**	**24,030**	**5,700**

			10%	1%	20%	3%	30%	5%
OUT OF FOOT-PRINT	**46,328**	**119,696**	**22,950**	**2,500**	**22,950**	**2,500**	**45,450**	**7,500**

TABLE 3 – CAPITAL COSTS (IN US2008$) FOR STUDY SCENARIOS WITH 30% WIND ENERGY AND 5% SOLAR ENERGY IN THE STUDY FOOTPRINT.

SCENARIO	WIND (MW)	SOLAR (MW)	TRANSMISSION (GW-MI)	WIND ($B)	SOLAR ($B)	INTERSTATE TRANSMISSION ($B)	TOTAL ($B)
IN-AREA	29,940	5,800	0	59.9	23.2	0	83.1
LOCAL PRIORITY	26,760	5,800	2,100	53.5	23.2	3.4	80.1
MEGA PROJECT	24,030	5,700	6,900	48.1	22.8	11.0	81.9

The rest of WECC includes 45,450 MW of wind ($91 billion), 4000 MW of PV ($16 billion), and 3500 MW of CSP ($14 billion). Intrastate transmission is not included in any of these scenario costs.

ANALYTICAL METHODS

Four primary analytical methods were used to evaluate the performance of the system with high penetrations of wind and solar generation: statistical analysis, hourly production simulation analysis, sub-hourly analysis using minute-to-minute simulations, and resource adequacy analysis.

Statistical analysis was used to quantify variability due to system load, as well as wind and solar generation over multiple time frames (annual, seasonal, daily, hourly, and 10-minute). The statistical analysis quantified the grid variability due to load alone over several time scales, using the interpolated hourly load data. The changes in grid variability due to wind and solar generation were also quantified for each scenario at various levels of aggregation. The statistical analysis also examined the forecast accuracy for wind generation.

Production simulation analysis with GE's MAPS (Multi-Area Production Simulation) program was used to evaluate hour-by-hour grid operation of each scenario for 3 years with different wind, solar, and load profiles. WECC was represented as a set of 106 zones, each with its own load profile, portfolio of generating plants, and transmission capacity with neighboring areas. The zones were grouped into 20 transmission areas. The production simulation results quantified numerous impacts of additional renewable generation on grid operation including:

- Amount of flexible generation on-line during a given hour, including its available ramp-up and ramp-down capability;
- Effects of day-ahead wind forecast alternatives in unit commitment;
- Changes in conventional generation dispatch;
- Changes in emissions (NO_x, SO_x, and CO_2) due to renewable generation;
- Changes in grid operation costs, revenues, and net cost of energy;
- Changes in transmission path loadings;
- Changes in use of hydro resources;
- Changes in use and economic value of energy storage.

Minute-to-minute simulation analysis was used to quantify grid performance trends and to investigate potential mitigation measures during challenging situations, such as large 1-hour, 3-hour and 6-hour changes in net load, high levels of wind and solar penetration, low load levels with minimal maneuverable generation on-line, and/or high wind forecast errors. Minute-to-minute analysis simulated the operation of dispatchable generation resources as well as variable wind and solar generation in the study footprint using one-minute time steps, while enforcing constraints related to unit maximum, minimum, ramp rate, intertie flow schedule, and regional Automatic Generator Control (AGC) functions.

Resource adequacy analysis involved loss-of-load-expectation (LOLE) calculations for the study footprint using the Multi-Area Reliability Simulation program, MARS. The analysis quantified the impact of wind and solar generation on overall reliability measures, as well as the capacity values of the wind and solar generation resources.

Impacts on system-level operating reserves were also analyzed using a variety of techniques including statistics, production simulation, and minute-to-minute simulation. This analysis quantified the effects of variability and uncertainty, and related that information to the system's increased need for operating reserves to maintain reliability and security.

The results from these analytical methods complemented each other, and provided a basis for developing observations, conclusions, and recommendations with respect to the successful integration of wind and solar generation into the WestConnect grid.

OPERATIONS WITH 35% RENEWABLES

The power system is designed to handle variability in load. With wind and solar, the power system is called on to handle variability in the net load (load minus wind minus solar), which can be considerable during certain periods of the year. Figure 2 shows the load, wind, solar, and net load profiles for the 30% case during two selected weeks in July and April. In the July week, (top plot), the net load (blue line at bottom edge) is not significantly impacted by wind and solar variation. However, in the April week (bottom plot), the high, variable wind output dominates the net load, especially during low load hours, leading to several hours of negative net load during the week. This week in April was the worst week in terms of operational challenges of the three years.

WWSIS finds that 35% renewable energy penetration is operationally feasible provided significant changes to current operating practice are made, including balancing area cooperation and sub-hourly generation and interchange schedule.

As an example of how the system would operate under less severe operating conditions, Figure 3 shows the generation dispatch for the same July week shown in Figure 2 for the In-Area Scenario. The left figure is without renewable generation and the right is the 30% case. Although the wind and solar generation are definitely noticeable, they primarily displace combined cycle and gas turbine generation, and have minimal impact on the steam coal units.

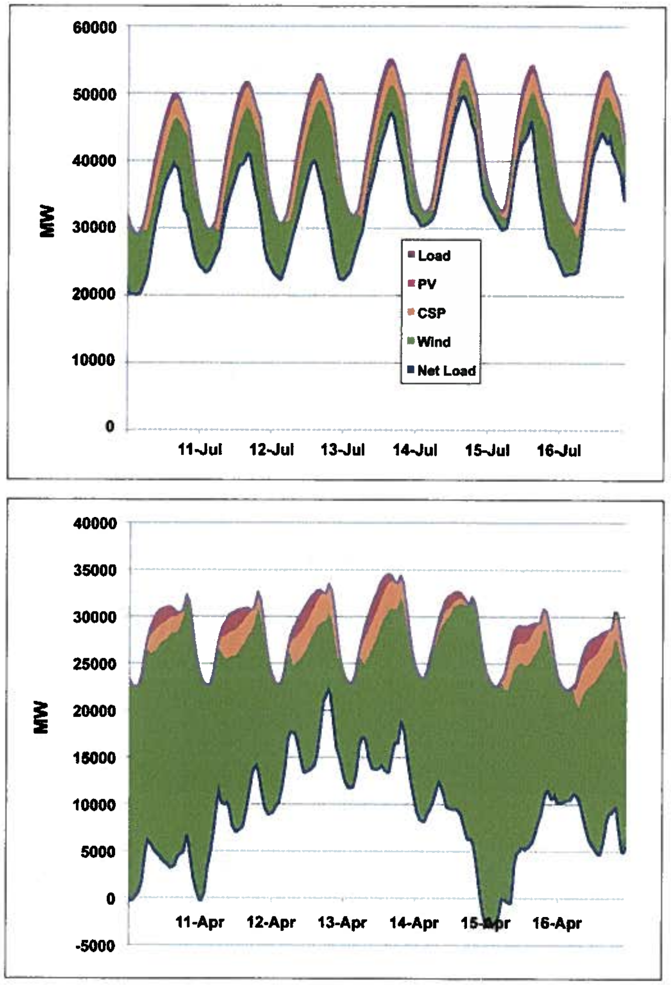


Figure 2 – With 35% renewables, system operators must now balance generation against the net load (blue) line. This may be straightforward (top, July) or challenging (bottom, April).

Figure 4 shows similar information for the April week shown in Figure 2. Here, operating the system with renewable generation is much more challenging. The combined cycle generation has been almost completely displaced, as have significant levels of coal generation. Nonetheless, the system can operate with balancing area cooperation. Without balancing area cooperation, operations during this week would be extremely difficult, if not impossible, for individual balancing areas.

How much renewable generation can the system handle? All three geographic scenarios show significant benefits with no negative effects in the 10% case. No significant adverse impacts were observed up to the 20% case in WestConnect, given balancing area cooperation. Increased renewable generation in the rest of WECC

[3] *WECC requires 6% of load to be held as contingency reserves, half of which is required to be spinning (i.e., synchronized to the grid) reserves.*

(20/20% case) led to increased stress on system operations within WestConnect, with some instances of insufficient reserves[3] due to wind and solar forecast error. These can be addressed, but the system has to work harder to absorb the renewables. Operations become more challenging for the 30% case in which load and contingency reserves are met only if the wind/solar forecasts are perfect. With imperfect forecasts, load is served but there are contingency reserve shortfalls. Extra spinning reserves can be held every hour of the year to meet those contingency reserve requirements, but the cost to hold enough to eliminate all contingency reserve shortfalls is very high. A more cost-effective alternative is to establish a demand response program or develop strategies to more accurately predict when these shortfalls occur and schedule more reserves during those hours or add additional quick start generation where needed. In the 20% and 30% cases, decreased flexibility of either the coal or hydro facilities made operation more difficult and increased the costs of integrating renewable generation.

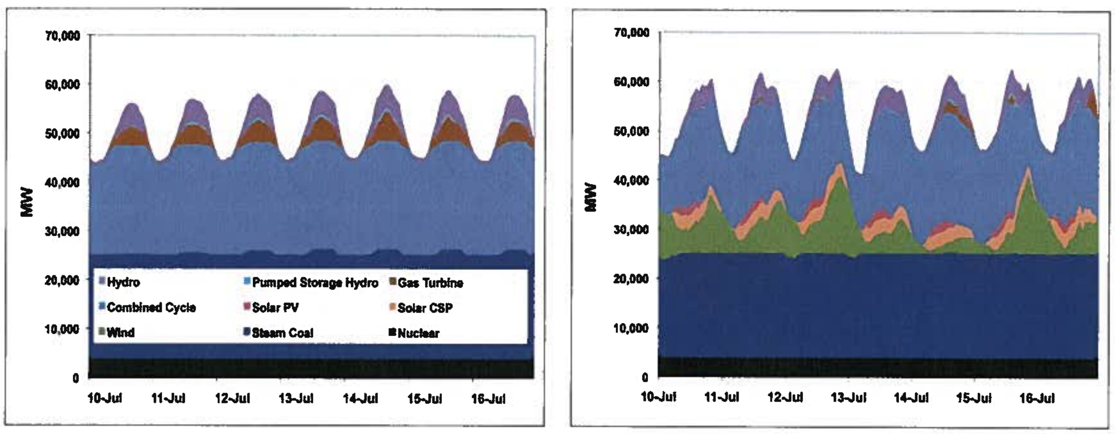


*Figure 3 – **35% renewables have a minor impact on other generators during an easy week in July, 2006.** WestConnect dispatch - no renewables (left) and 30% case (right)*

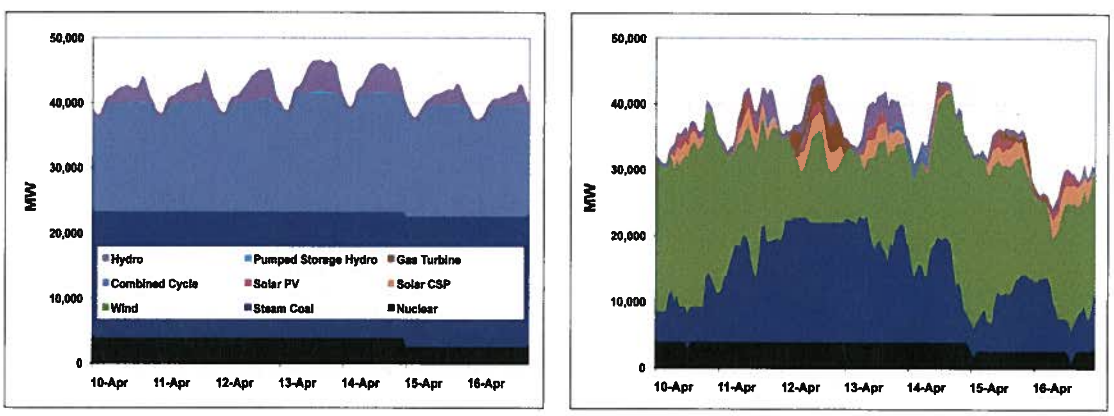


*Figure 4 – **35% renewables have a significant impact on other generation during the hardest week of the three years (mid-April 2006).** WestConnect dispatch - no renewables (left) and 30% case (right)*

BENEFITS OF 35% RENEWABLES

Wind and solar generation primarily displace gas resources nearly all hours of the year, given the fuel prices and carbon tax assumed for this study ($2/MBTU coal, $9.50/MBTU gas, $30/ton CO_2). Since gas-fired generation is typically more flexible than coal generation, the natural economic displacement of gas generation by wind and solar generation makes the balance of dispatchable generation on-line less flexible (fewer gas units, more coal units). Across WECC, operating costs drop by $20 billion/yr ($17 billion/yr in 2009$) from approx $50 billion/yr ($43 billion/yr in 2009$), resulting in a 40% savings due to offset fuel and emissions. This savings does not account for the capital or operating costs associated with the wind, solar, or transmission facilities, nor does it include any of the costs that would be required to implement the operational reforms needed to accommodate the renewables including balancing area cooperation or sub-hourly scheduling, although presumably some of this savings would be used to recover the capital costs of building this scenario, including payments to wind and solar generators. Figure 5 (left plot) shows the overall impact on the operating costs of WECC for the various penetration levels under the In-Area Scenario with a state-of-the-art (SOA) forecast. The 30% case shows WECC operating cost savings of $20 billion/yr ($17 billion/yr in 2009$) due to the wind and solar generation resources. Figure 5 (right plot) divides these values by the corresponding amount of renewable energy provided. In the 30% case, this equates to $80/MWh ($60/MWh in 2009$) of wind and solar energy produced. Lower penetrations of renewables showed values up to $88/MWh ($75/MWh in 2009$) of renewable energy produced (see Section 6.2). These operating cost savings would be applied toward the costs of the wind and solar energy, and depending on the magnitude of these costs, may or may not be sufficient to cover them.

The 30% case reduced fuel and emissions costs by 40% and CO_2 emissions by 25-45% across WECC.

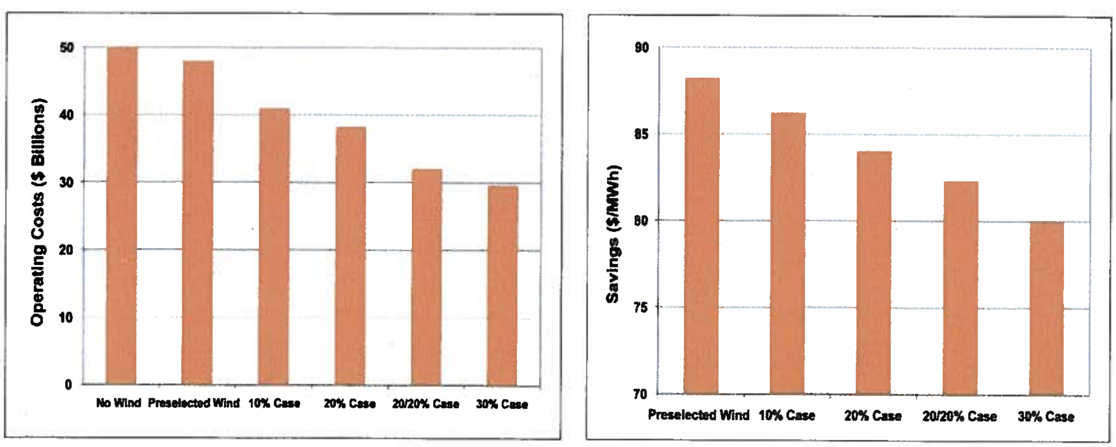


Figure 5 – WECC saves $20 billion ($17 billion in 2009$), or 40%, in annual operating costs in the 30% case, which is equivalent to $80 ($60 in 2009$) per MWh of wind and solar energy produced. Note: Chart on right starts at $70/MWh.

At a \$3.50/MBTU gas price, wind and solar primarily displace coal generation, leaving the more flexible gas generation resources to operate together with the wind and solar generation. With lower gas price assumptions, operating costs are reduced by about 40%, to \$46/MWh (\$39/MWh in 2009\$), but emissions reductions are higher.

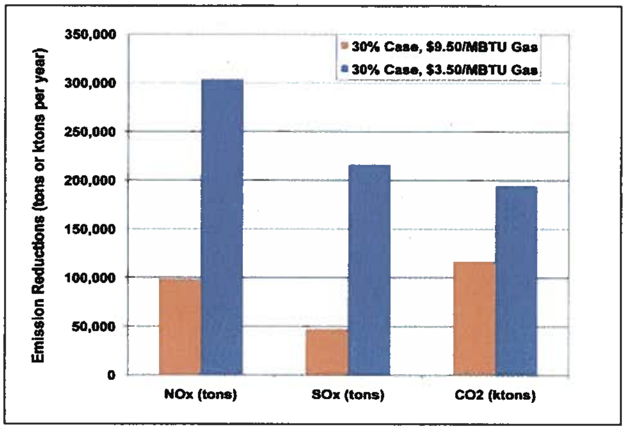


Figure 6 – Assuming \$9.50/MBTU gas, renewable energy displaces gas (orange). At lower gas prices (\$3.50/MBTU), coal is displaced instead, resulting in greater emissions reductions (blue).

Figure 6 shows the total WECC reductions in emissions for the 30% case. CO_2 emissions would be reduced by nearly 120 million tons/year, or approximately 25%, for the 30% case. SO_x emissions would be reduced by approximately 45,000 tons/year (~5%) and NO_x would be reduced nearly 100,000 tons/year (~15%) (see Section 6.2.1). At a \$3.50/MBTU gas price, CO_2 emissions are reduced by nearly 200 million tons/year (45%), and NO_x and SO_x by 300,000 tons/year (50%) and 220,000 tons/year (30%), respectively.

BALANCING AREA COOPERATION IS ESSENTIAL

There are three key benefits of balancing area cooperation: 1) aggregating diverse renewable resources over larger geographic areas reduces the overall variability of the renewables, 2) aggregating the load reduces the overall variability of the load, and 3) aggregating the non-renewable balance of generation provides access to more balancing (and more flexible) resources. Figure 7 shows the reduced-variability benefit arising from aggregating smaller transmission areas into the WestConnect footprint. Variability for small areas such as Colorado-West (CO-W) or Wyoming (WY) increases significantly as renewable penetrations increase from the 10% to the 30% case This effect becomes even more extreme at a more granular level, e.g., for specific balancing areas within

The technical analysis performed in this study shows that it is feasible for the WestConnect region to accommodate 30% wind and 5% solar energy penetration, but it would require extensive balancing area cooperation or consolidation, real or virtual.

a state (see Section 7.1). However, when the balancing areas across WestConnect are aggregated, there is only a slight increase in variability with increased renewables penetrations, and even a slight decrease in variability WECC-wide.

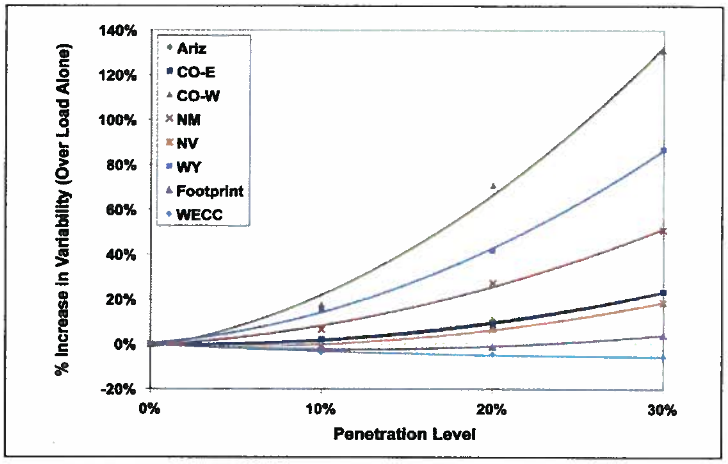


Figure 7 – The variability of the net load increases with increasing renewable energy penetration. Aggregating several transmission areas over the WestConnect footprint results in reduced variability. Percent increase in the standard deviation of the hourly changes of the net load in all areas for In-Area Scenario.

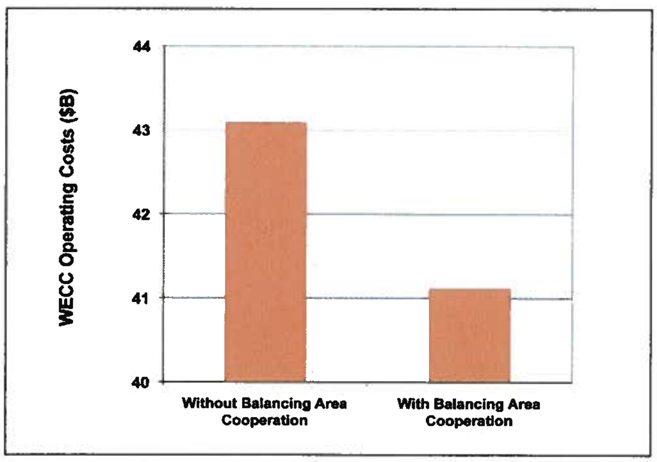


Figure 8 – WECC can save $2 billion ($1.7 billion in 2009$) by holding spinning reserves as 5 large regions (right) rather than many smaller zones (left).

From an operational perspective, balancing area cooperation can lead to cost savings because reserves can be pooled. A sensitivity analysis was performed, running WECC as 106 zones (which are roughly equivalent to balancing areas in the southwest, but there are multiple zones per balancing area in the northwest) versus 5 large regions.

Balancing area (BA) cooperation can take many forms and means different things to different people. In WWSIS, cooperation is modeled by assuming:

- All generation resources, across all BAs, are committed from a common regional generation stack on a least-cost basis
- Generation commitments assume physical transmission capability is available for import or export of power transfers between BAs
- All generation dispatches are made on a least-marginal-cost basis
- All regional reserves are shared across BAs; i.e., the most economic resources for reserves are used
- Day-ahead generation dispatch and inter-area transmission schedules can be modified during operation to enable sharing of load-following, regulation, and reserves

Mechanisms to enable these aspects of cooperation are numerous, and include facets currently used or proposed in WECC such as the ACE diversity interchange (ADI), dynamic scheduling, an energy imbalance service, and other means of consolidating BA services. Many technical and institutional barriers will need to be addressed to achieve the level of cooperation of the work presented here.

Figure 8 shows the $2 billion ($1.7 billion in 2009$) savings in WECC operating costs in the 10% case. There are significant savings from sharing reserves over larger regions, irrespective of the renewables on the system.

SUB-HOURLY SCHEDULING IS CRITICAL

The current practice of scheduling both the generation and interstate exchange only once each hour has a significant impact on the regulation duty. At high penetration levels, such hourly schedule changes can use most, if not all, of the available regulation capability to compensate for Area Control Error (ACE) excursions during large scheduled ramps. This can leave no regulation capability for the sub-hourly variability.

The minute-to-minute simulations showed that the current practice of hourly scheduling has a greater impact on the regulation requirements than does the wind and solar variability.

Sub-hourly scheduling can substantially reduce the maneuvering duty imposed on the units providing load following. In the 30% case, the fast maneuvering of combined cycle plants with sub-hourly scheduling is about half of that with hourly scheduling, as shown in Figure 9. Sub-hourly scheduling in the 30% case is roughly equivalent to the 20/20% case with hourly scheduling. Improvements in plant efficiency and reductions in O&M costs, while difficult to quantify, are expected from this smoother operation.

Sub-hourly scheduling will be required to successfully operate the system at high penetration levels without significantly increased regulating reserves.

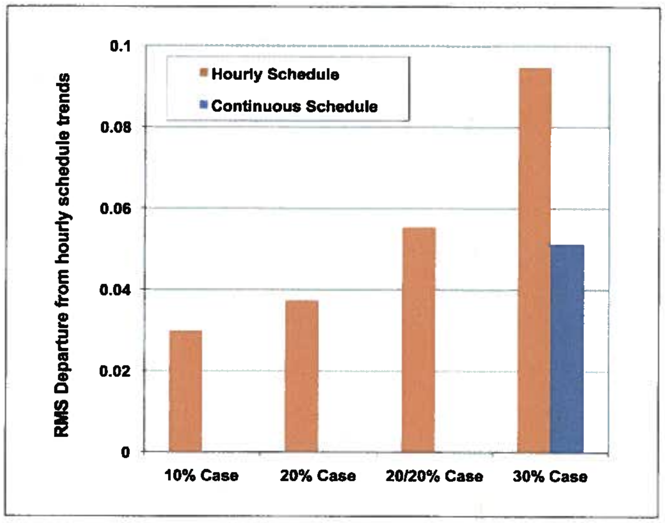


Figure 9 – Fast maneuvering duty of combined cycle units can be cut in half by moving from hourly to sub-hourly scheduling.

UNCERTAINTY (FORECAST ERROR) RESULTS IN THE BIGGEST IMPACT ON THE SYSTEM

Integrating day-ahead wind and solar forecasts into the unit commitment process is essential to help mitigate the uncertainty of wind and solar generation. Even though SOA wind and solar forecasts are imperfect and sometimes result in reserve shortfalls due to missed forecasts, it is still beneficial to incorporate them into the day-ahead scheduling process, because this will reduce the amount of shortfalls. Over the course of the year, use of these forecasts reduces WECC operating costs by up to 14%, or $5 billion/yr ($4 billion/yr in 2009$), which is $12-20/MWh ($10-17/MWh in 2009$) of wind and solar generation. The left side of Figure 10 shows the WECC-wide operating cost savings for using SOA forecasts compared to ignoring wind in the day-ahead commitment. The right side shows the incremental cost savings for perfect wind and solar day-ahead forecasts, which would reduce WECC operating costs by another $500 million/yr ($425 million/yr in 2009$) in the 30% case (see Section 6.2.1), or $1-2/MWh ($0.9-1.7/MWh in 2009$) of wind and solar generation.

Using state-of-the-art wind and solar forecasts in day-ahead unit commitment is essential and would reduce annual WECC operating costs by up to $5 billion ($4 billion in 2009$) or $12-20/MWh ($10-17/MWh in 2009$) of renewable energy, compared to ignoring renewables in the unit commitment process. Perfect forecasts would reduce annual costs by another $500 million ($425 million in 2009$) or $1-2/MWh ($0.9-$1.7/MWh in 2009$) of renewable energy.

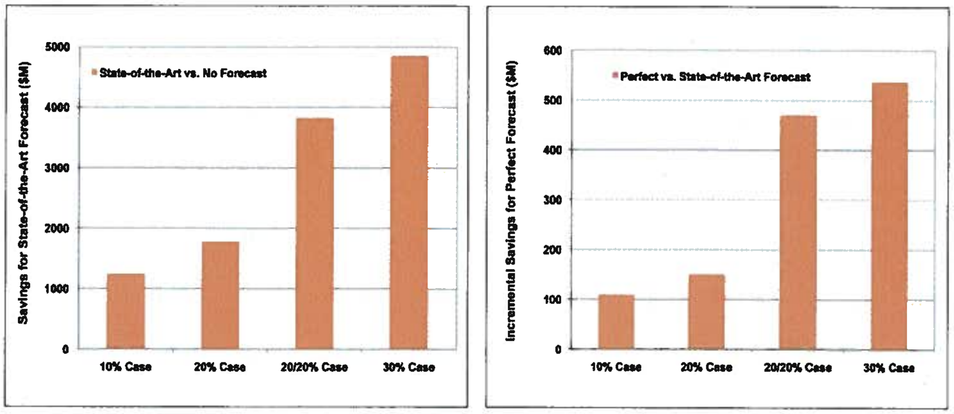


Figure 10 – WECC saves $1-5 billion ($1-4 billion in 2009$) in annual operating costs just by using a SOA day-ahead forecast in the unit commitment process (left). Incremental savings for perfect forecasts are an order of magnitude less (right).

THE IMPACTS OF EXTREME FORECAST ERRORS ON CONTINGENCY RESERVE SHORTFALLS

While on average, wind forecast error is not very large (8% mean absolute error across WestConnect), there are hours when wind forecast errors can be extreme, ranging up to over 11,000 MW of over- or under-forecast in WestConnect. Severe over-forecasts can result in contingency reserve shortfalls; severe under-forecasts can result in curtailment of wind.

Operating rules dictate that systems must carry contingency reserves to cover system events, such as tripping of a large generator. In WECC, the spinning portion of these contingency reserves is equivalent to 3% of the system load. Applying these WECC rules, severe over-forecasts can lead to under-commitment of generation units, which can result in contingency reserve shortfalls if insufficient quick-start capacity is available.

If the forecast is perfect, there are no contingency reserve shortfalls, even in the 30% case. With a SOA forecast, Figure 11 shows that these contingency reserve shortfalls become an issue in the 30% case. It should be noted, however, that even these shortfalls represent only a tiny percentage (~0.005%) of the total load energy.

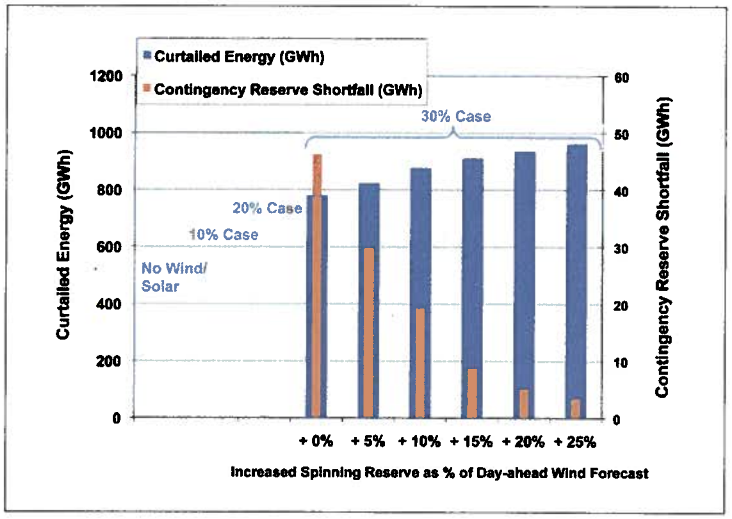


Figure 11 – Contingency reserve shortfalls start to become an issue in the 30% case. Increasing spinning reserve can reduce the shortfalls but even increasing spinning reserves by 25% of the day-ahead wind forecast does not completely eliminate reserve shortfalls. *Hourly production simulation analysis shows spilled energy, or curtailment, on the left axis and contingency reserve shortfalls on the right axis for the In-Area Scenario with no wind/solar, the 10, 20, and 30% case for a SOA forecast. The five bars on the right show the effect of increasing spinning reserve by 5, 10, 15, 20, and 25% of the day-ahead wind forecast.*

Spinning reserves can be increased to cover these contingency reserve shortfalls, but at a cost. Figure 11 shows the impact of increasing spinning reserves by 5, 10, 15, 20 and 25% of the day-ahead wind forecast. However, each additional 5% increment of committed spinning reserve is increasingly expensive, as shown in Figure 12, and even with a 25% increase in committed spinning reserves, not all contingency reserve shortfalls are eliminated.

It is more cost-effective to have demand response address the 89 hours of contingency reserve shortfalls rather than increase spin for 8760 hours of the year. Demand response can save up to $600M/yr ($510M/yr in 2009$) in operating costs versus committing additional spinning reserves.

The average cost of increasing reserves is shown in Figure 12. Increasing the committed spinning reserve by 5% of the wind forecast increases WECC operating costs by over $3,000 per MWh ($2,550/MWh in 2009$) of reduced reserve shortfall. Expressed another way, it would be comparable to pay some of the load $3,000/MWh ($2,550/MWh in 2009$) to drop off rather than increasing the spinning reserve by 5% of the forecast. At the other extreme, if spinning reserve is increased by 25%, it would cost an average of roughly $13,600/MWh ($11,600/MWh in 2009$) of reserve shortfall. The incremental reduction achieved by increasing the spinning reserve from 20% to 25% of the forecast would cost over $100,000/MWh ($85,000/MWh in 2009$). It should be more economic to use load participation (i.e., demand response) than to increase the spinning reserves to achieve the same objectives. Using load participation instead of committing additional generation for operating reserves would save up to $600 million ($510 million in 2009$) in operating costs per year (see Sections 5.4, 7.2, and 6.2.2).

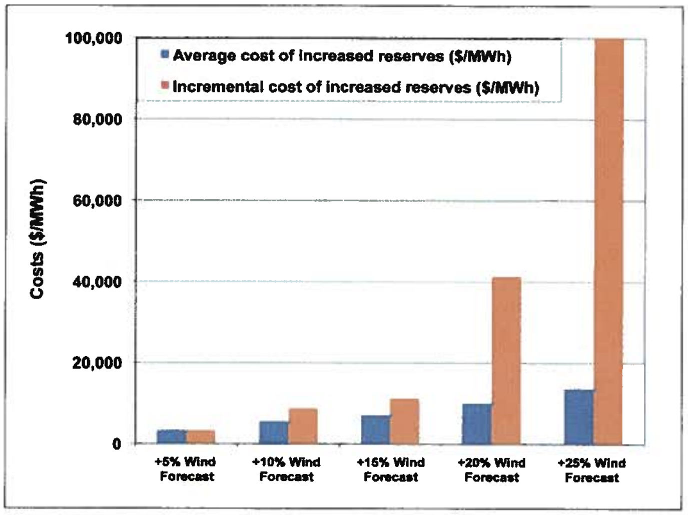


*Figure 12 – **The cost of increasing spinning reserves increases with higher percentages of spin. The incremental cost increases sharply at higher percentages of spin, indicating that the cost of reducing those final reserve shortfalls is prohibitively high.** The five bars show the effect of increasing spinning reserve by 5, 10, 15, 20, and 25% of the day-ahead wind forecast.*

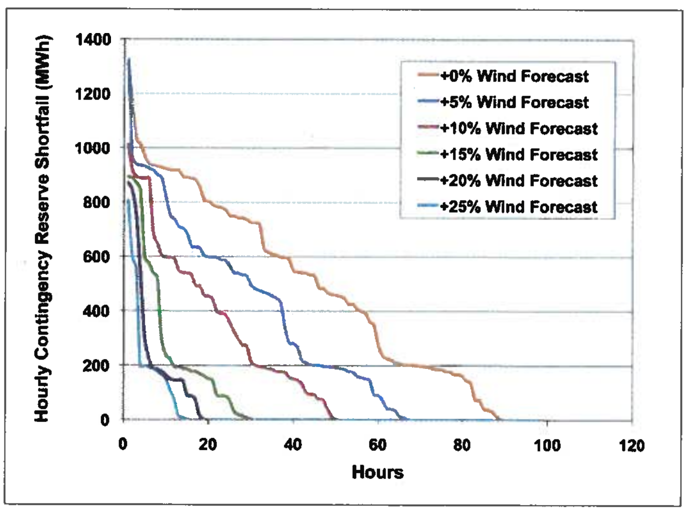


*Figure 13 – **A demand response program which requires load to participate in the 89 hours of the year that there are contingency reserve shortfalls is more cost-effective than increasing spin for each of the 8760 hours of the year.** Hourly contingency reserve-shortfall duration curves for the In-Area 30% case with a SOA forecast with no additional spinning reserves, and then with spinning reserves increased by 5, 10, 15, 20, and 25% of the day-ahead wind forecast.*

Instead of holding additional spinning reserve for each of the 8760 hours of the year, Figure 13 shows that a demand response program could address those 89 hours of the year when there is a contingency reserve shortfall and have a total participation of approximately 1300 MW of load. The contingency reserve shortfalls could also be met by a combination of increased spinning reserves and a smaller demand response program. An alternative to demand response or increased spinning reserve for every hour of the year could be dynamic allocation of spinning reserves based on better forecasting, improved reserve policies, and more accurate prediction of when shortfalls are likely to occur.

HOW OFTEN IS WIND CURTAILED?

Uncertainty drives both curtailment and reserve shortfalls. With a perfect forecast, no wind or solar curtailment was necessary in any of the scenarios. Even in the few hours when the renewable generation exceeded the load in WestConnect, there was sufficient flexibility within WECC to absorb all of the generation. With a SOA forecast, no curtailment occurred up through the 20% case (see Figure 11). The hourly production simulations showed about 800 GWh of wind curtailment in the 30% case, representing less than 0.5% of the total wind energy production. In addition, the minute-to-minute analysis indicated that more wind curtailment may be required under some combinations of low load and high wind. Altogether, wind curtailment in the 30% case is estimated to be on the order of 1% or less of the total wind energy. Curtailment is also affected by flexibility of the balance of generation, e.g., raising the minimum operating point of the coal units to 70% increased the wind curtailment slightly (see Sections 6.2 and 6.4.4).

THE EFFECT OF VARIABILITY – ARE ADDITIONAL RESERVES NECESSARY?

In addition to contingency reserves, utilities are required to hold variability or load following reserves to cover 10-minute load variability 95% of the time. Typically, utilities do not commit additional variability reserves because the existing dispatchable generating fleet can adequately cover this variability reserve requirement. With wind and solar, the net load variability increases and in the 30% case, the average variability reserve requirement doubles. However, when wind and solar are added to the system, thermal units are backed down because it is sometimes more economical to back down a unit rather than to decommit it. This results in more up-reserves available than in the case when there is no wind and solar, as shown in Figure 14. Therefore, commitment of additional reserves is not needed to cover variability in the study footprint. Figure 14 shows a duration curve of the total amount of up-reserves in the committed generation after the contingency reserve requirement is subtracted out, showing that 95% of the time, there are adequate up-reserves in the 30% Local Priority case.

While the need for variability reserves doubles in the 30% wind case, the backing down of conventional units results in more available up-reserves. Therefore, commitment of additional reserves is not needed to cover the increased variability.

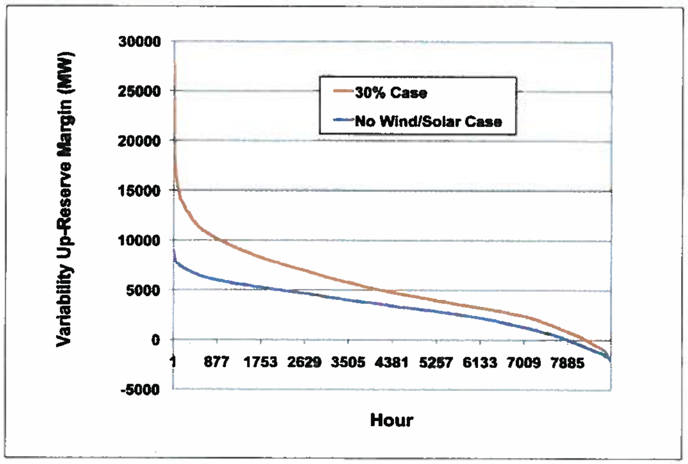


*Figure 14 – **There are more up-reserves available in the 30% case than in the no wind/solar case because the additional renewable energy generation causes many conventional units to be backed down.** Variability Up-Reserve Margin – Local Priority 30% vs. No Wind or Solar Case.*

Regulating reserves are a subset of the fast variability requirement, but are held separately from the 10-minute variability reserves. Regulating reserves are required to be automatically controlled through AGC. While WWSIS did not evaluate which units were on AGC, the minute-to-minute analysis showed that sufficient regulating reserve capability was available in WestConnect.

Wind plants can be curtailed to provide down regulating reserves instead of moving regulating units. Even so, curtailment is estimated to be on the order of 1% or less of total wind energy in the 30% case.

Down reserves can be handled through wind curtailment when other resources are depleted. A wind plant can reduce its output very quickly in response to a command signal. Simulations in this study show that down reserves can be implemented through command signals (ACE signals) from system operators. With extensive balancing area cooperation, WestConnect can accommodate large amounts of renewables, and curtailment of wind is expected to be on the order of 1% or less in the 30% case.

WHAT IS THE EFFECT OF DIFFERENT TRANSMISSION AND GEOGRAPHIC SCENARIOS?

The In-Area, Local Priority, and Mega Project Scenarios showed similar overall performance and economics for a given penetration level. This indicates that the specific locations of the wind and solar resources within WestConnect are not critical, provided there is adequate transmission infrastructure and access, and balancing area cooperation (see Sections 4.2.3, 5.5, 6.4.1, 6.4.6, 7.3.1). The assumption that existing transmission capacity can be fully utilized is an important change from present practice underpinning these results.

Figure 15 shows the study footprint's monthly wind and solar energy as a percentage of load energy for all three scenarios in the 30% case in 2006.

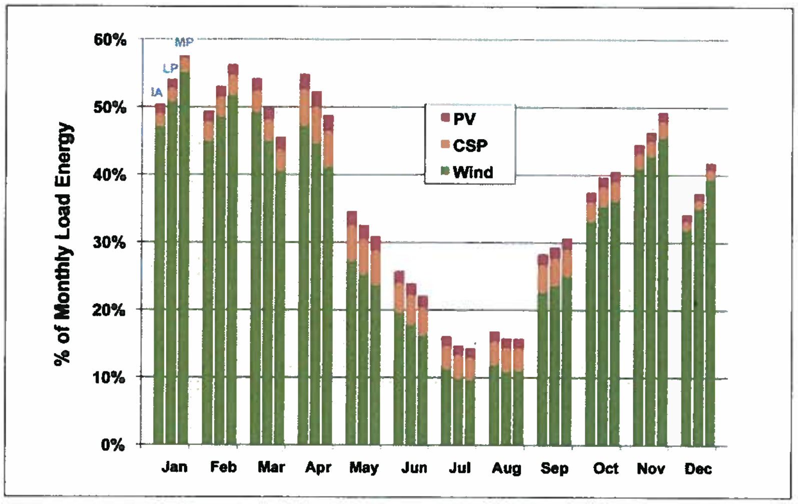


Figure 15 – The month-to-month variation of wind and solar penetration is greater than the scenario-to-scenario variation.

The plots clearly illustrate that 1) despite the month-to-month variation, there is relatively little difference among scenarios at the footprint resolution and 2) there is significant month–to-month variation in energy across the year. In fact, there is more interannual variation in each month's penetration levels than there is inter-scenario variation (see Section 4.1.1-4.1.2)

The total WECC operating cost savings per MWh of renewable energy for the different scenarios was also very similar across the three geographic scenarios, with only a slight increase in value as the wind plant locations were shifted to the higher capacity factor sites in the Local Priority and Mega Project Scenarios (see Section 6.4.1)

IS NEW LONG DISTANCE TRANSMISSION NEEDED?

Sufficient intra-area transmission within each state or transmission area for renewable energy generation to access load or bulk transmission is needed. However, the In-Area Scenario, which included no additional long distance, interstate transmission, worked just as well operationally as the other scenarios. A sensitivity case examined the impact of the interstate transmission build-outs in the Local Priority and Mega Project Scenarios (which required $3.4 and $11 billion dollars, in 2008$, of interstate transmission respectively). Figure 16 shows the increased annual operating

Up to 20% renewable penetration could be achieved with little or no new long distance, interstate transmission additions, assuming full utilization of existing transmission capacity.

costs for the cases in which the new interstate transmission build-outs associated with the Local Priority and Mega Project Scenarios were eliminated. These increased costs are modest because renewables have displaced other generation and freed up transmission capacity. Assuming renewables have full access to this newly opened up capacity, there is less need for new transmission.

Assuming a 15% fixed charge rate, the 30% Local Priority Scenario would justify about $2 billion ($1.7 billion in 2009$) in transmission investments and the Mega Project Scenario would justify a little over $10 billion ($8.5 billion in 2009$). This rough estimate suggests that the full-scale transmission build-out might be justified in the 30% Mega Project Scenario, but not at lower penetrations in the Mega Project or for any of the other scenarios. A more limited transmission build-out may be justified for the Local Priority Scenario. Of course, these estimates do not include any reliability benefits that would be realized from adding more transmission. All scenarios could be built out to the 10% case without any new interstate transmission (see Section 6.4.6).

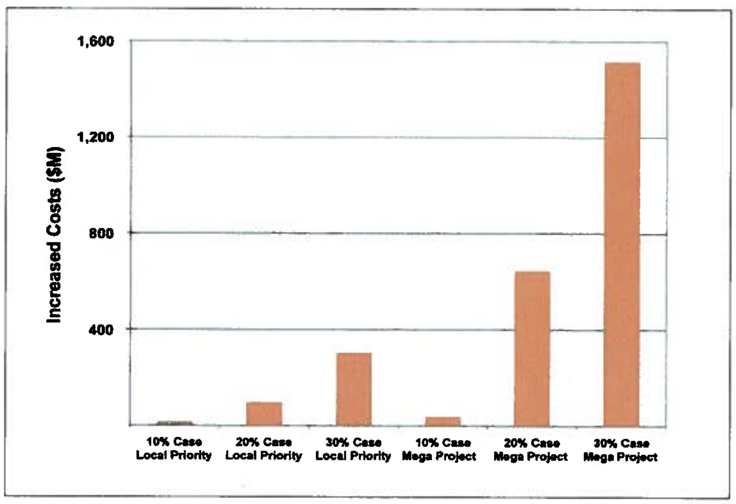


Figure 16 – Building the Local Priority and Mega Project Scenarios without the accompanying interstate transmission, increases costs at high penetrations in the Mega Project Scenario.

IS ADDITIONAL STORAGE NEEDED?

Storage can provide many benefits to the system, including price arbitrage (charging when spot prices are low and discharging when prices are high), reliability, and ancillary services. Pumped storage hydro (PSH), solar thermal storage, and plug-in hybrid electric vehicles (PHEVs) were examined in WWSIS, with the largest focus on PSH (see Chapter 8). WWSIS evaluated only the price arbitrage part of the value proposition for PSH and found it much less than sufficient to economically justify additional storage facilities.

In the 10% and 20% wind penetration scenarios, gas generation is always on the margin (meaning that there are only small spot price variations during most days). As a result, there is no apparent opportunity to economically justify energy storage based on price arbitrage. Spot price variations increase in the 30% wind penetration scenarios, primarily due to errors in day-ahead wind energy forecasts. Occasionally, the price swings are very large. However, because this is driven by forecast uncertainty, it is not possible to strategically schedule the use of storage resources to take advantage of the price variations (and subsequently help eliminate the operational problems due to wind forecast errors).

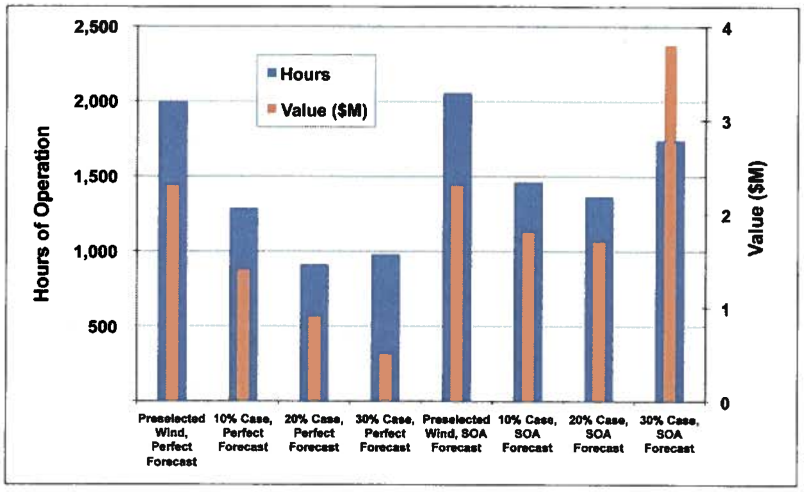


Figure 17 – A new 100-MW PSH plant with perfect pricing foresight would earn approximately $4 million/yr ($3.4million/yr in 2009$) from price arbitrage in the 30% case.

To examine a best-case scenario for storage, a new 100-MW PSH plant was added to the system and given perfect foresight of spot prices so that it could be dispatched to optimize revenue. The results in Figure 17 show the resulting number of operating hours and value. With no renewables, the PSH unit would run about 2200 hours (total pumping and generating time) and have an operating value of about $2.6 million ($2.2 million in 2009$) for the year. With a perfect forecast, the value of the PSH unit decreased as the renewable penetration increased, due to decreased spot prices. With 30% penetration and a perfect forecast the 100-MW PSH plant only had an annual operating value of $0.5 million ($0.4 million in 2009$) which would only yield a capitalized value of about $35/kW ($30/kW in 2009$). With an SOA forecast, spot prices are higher due to forecast error, and the 30% case increased the PSH annual operating value to $3.8 M ($3.2M in 2009$). However, this is several times less than would be required to recover costs for a new PSH plant[4] (see Section 8).

WHAT IS THE BENEFIT OF FLEXIBILITY IN THE REST OF THE GENERATION FLEET?

System flexibility is the key to accommodating increased renewable generation. WWSIS finds that at higher (30% case) penetration levels, decreased flexibility of either the coal or hydro facilities made operation more difficult and increased the costs of integrating the renewable generation.

ALLOWING HYDRO TO PROVIDE LOAD FOLLOWING FOR WIND/SOLAR VARIABILITY IS HELPFUL

Hydro generation is capable of quick start/stop cycling and fast ramping, which makes it a good partner for variable wind and solar generation. Sensitivity analyses were conducted to examine the effects of hydro constraints on operating costs (see Section 6.4.2).

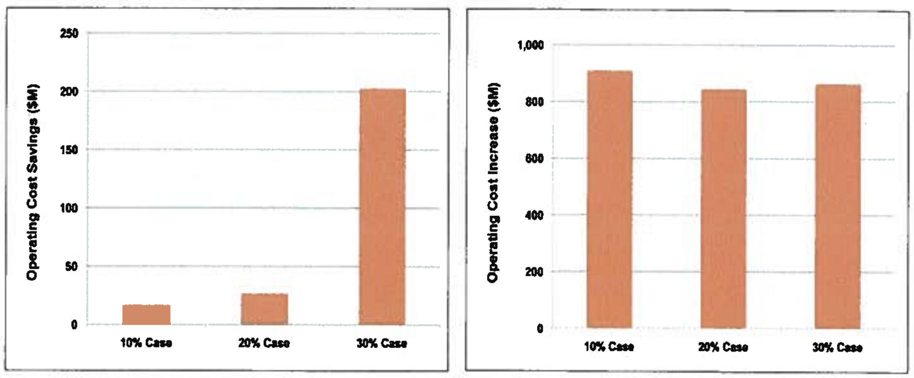


***Figure 18 – Decreasing the flexibility of the hydro system increases costs.** Operating cost savings for hydro dispatch to net load (left), and operating cost increase for constant output hydro operation (right), WECC.*

This study assumed that hydro generation is normally committed and dispatched to serve daily peak net-load periods, while respecting the minimum operating points on the hydro units. The left side of Figure 18 shows the impact of adjusting the hydro schedules to account for the day-ahead renewable forecasts. Although the impact is relatively small at low levels of penetration, the WECC operating costs would be reduced by $200 million/yr ($170 million/yr in 2009$) at the 30% case, increasing the value of wind and solar energy by about $1/MWh ($0.9/MWh in 2009$).

The right side of Figure 18 examines the impact if hydro operation were severely constrained, such as a requirement to maintain constant river flow. In this case, the WECC operating costs would increase by up to $1 billion/yr ($0.9 billion/yr in 2009$). Clearly it is important to maintain as much operational flexibility as possible with the hydro generation (see Section 6.4.2).

[4] Assuming $1200-2000/kW capital cost and a fixed charge rate of 15% for a new PSH, $18-30 million annually would be needed to recover capital costs.

CONSTRAINTS ON COAL PLANTS RESULT IN HIGHER OPERATING COSTS

In WWSIS, coal plants were assumed to be able to operate down to minimum generation levels of 40% of nameplate capacity. WWSIS finds that higher minimum generation levels result in increased operating costs.

A sensitivity case explored the impact of varying coal plant minimum loading on system operating costs. Increasing the minimum loading had minimal impact with wind penetrations less than 20%. At the 30% scenario, the impact becomes more noticeable, as shown in Figure 19. If coal plants are allowed to only operate above 70% load, then WECC operating costs would increase by nearly $160 million/yr ($136 million/yr in 2009$). See Section 6.4.4.

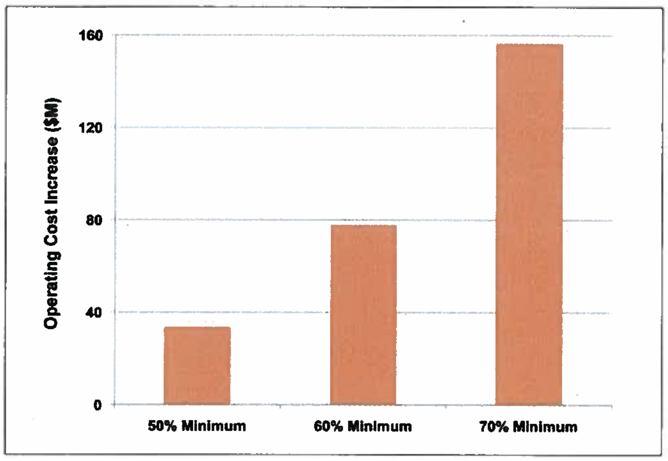


*Figure 19 – **Decreasing the flexibility of the coal fleet by increasing minimum generation levels on coal plants increases costs.** Increased WECC operating costs over 40% minimum ratings on coal plants, 30% case.*

WHAT IS THE CONTRIBUTION OF RENEWABLES TO RESOURCE ADEQUACY?

Variable resources such as wind and solar PV are primarily energy resources rather than capacity resources. However, they provide some contribution to reliability (resource adequacy). A range of capacity valuation techniques based on traditional loss-of-load-expectation (LOLE) data were evaluated to consider the variability inherent with the renewable generation. This was conducted for WestConnect assuming no transmission constraints within the study footprint and no interconnections with the rest of WECC, so that the capacity value characteristics of the renewable generation could be isolated.

Table 4 shows capacity values of wind based on daily LOLE which were typical of the overall analysis. Wind generation resources selected for this study were found to have capacity values in the range of 10% to 15%. Wind plant energy output tends to be higher during winter and spring seasons, and during nighttime hours, which is contrary to system peak load periods. Hence, the capacity value is low relative to the plant rating. PV solar plants have capacity values in the range of 25% to 30%. Although PV solar produces its energy during the daytime, output tends to decline in the late afternoon and early evening when peak load hours often occur. The PV output was based on the DC rating of the system; it would be 23% higher if based on the AC rating and included inverter and other losses from the outset. Concentrating solar plants with thermal energy storage have capacity values in the range of 90% to 95%, similar to thermal generating plants. Their maximum energy production tends to be during the long summer days, and the storage capability extends the energy output through the late afternoon and early evening hours, when peak loads occur (see Sections 4.2, 4.3, and 9.2 through 9.7).

Wind was found to have capacity values of 10-15%; PV was 25-30%; and CSP with 6 hours of thermal energy storage was 90-95%.

TABLE 4 – CAPACITY VALUES FOR 2004-2006.

CASE	WIND ONLY	PV ONLY	CSP ONLY	WIND+PV+CSP
10%	13.5%	35.0%	94.5%	18.2%
20%	12.8%	29.3%	94.8%	19.7%
30%	12.3%	27.7%	95.3%	19.8%

CONCLUSIONS AND NEXT STEPS

The technical analysis performed in this study shows that it is feasible for the WestConnect region to accommodate 30% wind and 5% solar energy penetration. This requires key changes to current practice, including substantial balancing area cooperation, sub-hourly scheduling, and access to underutilized transmission capacity.

WWSIS finds that both variability and uncertainty of wind and solar generation impacts grid operations. However, the uncertainty (due to imperfect forecasts) leads to a greater impact on operations and results in some contingency reserve shortfalls and some curtailment, both of which are relatively small. The variability leads to a greater sub-hourly variability reserve requirement, but because conventional units are backed down, the system naturally has extra reserve margins.

This study has established both the potential and the challenges of large scale integration of wind and solar generation in WestConnect and, more broadly, in WECC. However, changes of this magnitude warrant further investigation. The project team regards the following as valuable topics for exploration:

- Characterization of the capabilities of the non-renewable generation portfolio in greater detail (e.g., minimum turndown, ramp rates, cost of additional wear and tear);
- Changes in non-renewable generation portfolio (e.g., impact of retirements, characteristics, and value of possible fleet additions or upgrades);
- Reserve requirements and strategies (e.g., off-line reserves, reserves from non-generation resources);
- Load participation or demand response (e.g., functionality, market structures, PHEV);
- Fuel sensitivities (e.g., price, carbon taxes, gas contracts and storage, hydro constraints and strategies);
- Forecasting (e.g., calibration of forecasting using field experience, strategies for use of short-term forecasting);
- Rolling unit commitment (e.g., scheduling units more frequently than once on a day-ahead basis);
- Transmission planning and reliability analyses (e.g., transient stability, voltage stability, protection and control, intra-area constraints and challenges);
- Hydro flexibility (e.g., calibration of hydro models with plant performance).

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